GENERATOR MAINTENANCE TESTING

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For the purpose of this article, generator maintenance testing refers to tests that are done generally off line or at some special condition, as opposed to on-line testing which is actually a form of monitoring for diagnostic purposes while the generator is producing power. However, there are certain on-line tests that are done and classified as testing rather than monitoring, because they are not done on a full-time basis, meaning continuously monitored. Those types are discussed here as well.

Tests on large turbogenerators are a very serious business. Improper testing or test preparation can cause expensive, unnecessary losses to the machine and expose the personnel to lethal dangers. Hence, tests must be carried out only by well-trained professionals, following all relevant and applicable rules and standards.

11.1 STATOR CORE MECHANICAL TESTS

11.1.1 CORE TIGHTNESS

Stator cores can become loose from vibration and thermal cycling. If they do, then there is concern for inter-laminar fretting of the insulation coating on the individual laminations. Loss of the inter-laminar insulation can cause shorts and local overheating of the core. To ensure the core is tight, a stator core tightness test can be done when the rotor is removed.

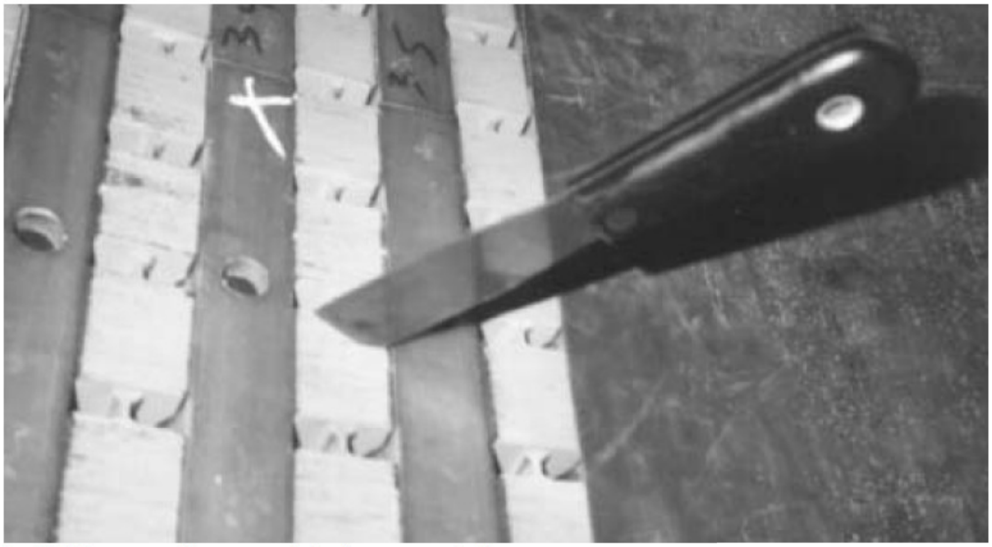


Fig. 11.1 Stator core tightness testing by knife insertion method.

The test is done by inserting a thin, tapered, and hardened steel knife blade between laminations to determine the degree of looseness in the stator iron (Fig. 11.1).

This test requires some experience to get a "feel" for what is or is not loose. However, in general, one should only be able to get the knife blade just into the core, if at all, and not be able to push it any distance inward, in the radial direction.

The testing should be repeated all around the circumference of the stator bore, and over the full length of the core, in random locations. Particular attention should be paid to the core ends, as this is where the majority of loosening generally occurs.

When looseness is found in the core, there are numerous methods available for remedying the situation. These include localized core stemming with shaped epoxy/glass inserts, retorquing of the core, and so on, up to re-stacking of the core iron.

11.1.2 CORE AND FRAME VIBRATION TESTING

The maximum vibration of the stator core and core frame should be less than 50ºm (about 2 mils) peak to peak (unfiltered), with no natural resonance within the frequency ranges of 50-75 Hz and 100-140 Hz for 60 Hz systems, and about 40-65 Hz and 80-120 Hz for 50 Hz systems. The problems associated with high vibrations are premature stator core inter-laminar and stator winding insulation wear, and structural problems with the core and frame. To maintain low vibration and avoid problems, it is best to have a tight core and to have good mechanical coupling between the core and frame. This ensures that no wear occurs between the two components at the keybars. Low absolute vibrations and low relative vibration between the core and frame, with the two components in phase, is a good indicator that the core and frame structure is sound.

Testing can be done off line or on line. However, for either type of test, vibration transducers (accelerometers) must be mounted on the core and frame, internal to the machine. This includes the stator center, both ends, and locations on the circumference based on the nodal vibration patterns of the stator (four nodes for two-pole machines and eight nodes for four-pole machines). The vibrations are generally measured in the radial and tangential directions when looking toward the end of the machine. In addition it is desirable to use a number of portable, magnetic based transducers, which may be moved around the outside of the generator casing, to ensure complete analysis of the machine.

Off-line testing is not generally done unless there is a known problem with core and frame vibration. The excitation source must be artificially applied in this method, and there are a couple of ways to accomplish this. One is to simply strike the frame with a heavy rubber hammer and measure the frequencies where the vibrations peak. However, this does not usually produce a significant result because the stimulus is so small. The other method is to attach a shaker device to the frame to stimulate the stator at a fixed frequency, and then measure the frequencies where the vibrations peak. The shaker method generally produces good results because there is a significant stimulus and it can be controlled. The problem with this type of testing is that it does not give an accurate picture of the true vibration of the core and frame in operation.

On-line testing is generally the best way to get a complete vibration analysis of the core and frame. With on-line testing it is possible to look at all operating modes of the stator and determine which parameter has the most influence on vibration. During testing the variable parameters are stator current, field current, hydrogen pressure, and hydrogen temperature. In some cases it has also been useful to valve out individual hydrogen coolers, successively, to change the cooling pattern and determine its effect on the core and frame vibration.

When core and/or frame vibrations are present, it is necessary to determine if the vibrations are most prevalent on the core or frame, and if the two components require better coupling to each other. The possibilities of what may be found on any individual machine are too vast to cover here. However, as a rule-of-thumb, it is often found that the core and frame will have a natural frequency that is too close to the forbidden zones, and that they do require some artificial means to ensure better mechanical coupling between the two. In such cases, vibration damping is also usually required. When trying to dampen excessive vibrations, there are two methods employed. The first method requires adding mass to lower the natural frequency. The second method entails stiffening the structure to raise the natural frequency. Adding mass can be difficult if there is no good place to attach it, and stiffening can sometimes cause problems with overstressing the frame welds, causing them to crack.

Stator core and frame vibration problems are very complex to analyze, and even more complex and expensive to solve. They should be addressed on a machine-to-machine basis, as each case will be unique.

11.2 STATOR CORE ELECTRICAL TESTS

11.2.1 EL-CID TESTING

The EL-CID (Electromagnetic-Core Imperfection Detector) technique was originally devised as portable test equipment for inspection and repair of rotating electric machine stator cores. It was devised as a low excitation power alternative to the high power level stator core flux test, for looking for stator core inter-laminar insulation problems. Its application has been shown to be applicable to turbine generators, hydraulic generators, small generators, and large motors.

However, here we are confined to the class of large two and four pole, round-rotor machines, commonly referred to as turbine-driven generators.

The information contained in this section is a brief discussion of the EL-CID test technique and basic interpretation of results.

Traditionally stator core inter-laminar insulation testing has been done using the “ring” or “loop” flux test method, in which rated or near-rated flux is induced in the stator core yoke. This, in turn, induces circulating currents from the faulted area usually to the back of the core, at the core-to-keybar interface (Fig. 11.2).

These circulating currents cause excessive heating in areas where the stator iron is damaged. The heat produced is generally detected and quantified using established infrared techniques. This method has been proved to be successful over the years, but it requires a large power source and considerable time, manpower and resources to complete.

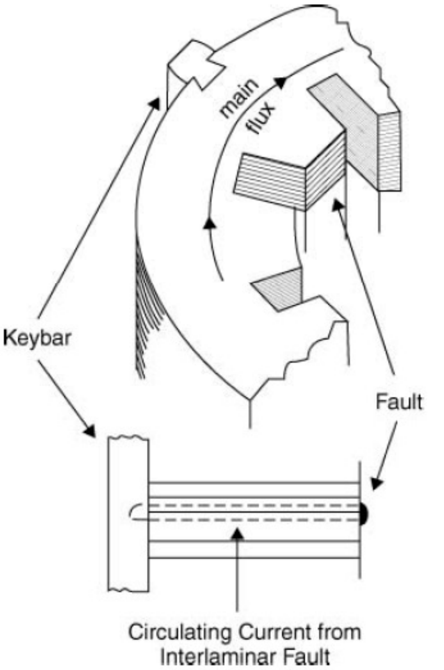


Fig. 11.2 Stator core fault current path from fault to core back at the keybars, by induced flux. (Courtesy of ADWEL International).

Starting in the early 1980s, the EL-CID test has been developed as an alternative to the ring flux test. The technique is based on the detection of core faults by measuring the magnetic flux resulting from the current flowing in the fault area, at only 3 to 4% of rated flux in the core. Furthermore the test usually requires only two or even one man to complete (using the latest version) in less than one eight-hour shift.

EL-CID TEST PROCEDURE

The level of excitation to produce the desired flux in the stator core-back area is generally determined by a combination of the stator design parameters, and the power supply available to achieve the required flux level. For most generators, the standard 120 V AC (North America, etc.) or the 230 V AC (Europe, etc.) outlet, with a current capacity of 15 to 20 amp is usually adequate.

The characteristics of most stators are such that four to seven turns of a #10 AWG insulated wire (2.5 mm2) can be used to carry the excitation current for the test. The winding is then energized to the required volts per turns to produce approximately 3 to 4% of rated flux, usually corresponding to around 5 volts per meter across the stator iron. A Powerstat or Variac is best used for voltage and supply current control.

The signal-processing unit of the EL-CID test equipment measures detected fault current (in quadrature mode) in mA. By theory and experimentation, a measurement of at least ±100 mA is required at 4% excitation of the core before it is considered that the core has significant damage affecting the interlaminar insulation.

The excitation winding and power supply are set-up during the test as shown in Figure 11.3. The EL-CID equipment is set up as shown in Figure 11.4 (original analog set) and Figure

11.5 (newer digital set).

In the older analog sets, a separate coil is placed in the bore over undamaged iron as shown in Figure 11.4 to supply the reference signal. In the newer digital version, a CT (shown in Fig. 11.5) is placed around the excitation winding to reference the supply signal. The CT was also an option on later analog sets. The digital equipment uses a laptop computer to store the axial traces, whereas a plotter was used in the original version.

The sensor head (chattock potentiometer) is pulled axially along the core at a speed slower than one meter every twenty seconds and always bridging two stator teeth as shown in Figure 11.6. (The slower speed is important, as the standard chattock coil has a magnetic sense area of only 4 mm diameter, and both the digital and analog systems have a definite time needed to record the phase/quad signals to sufficient resolution. The digital set records the phase and quad values every 2 mm. Any faster testing results in some missed test points in the digital system or potential inaccuracy due to settling time on the analog system).

The fault current signal is read directly off the signal processor meter, and input to a computer or chart recorder to trace out the readings as a function of the axial position along the stator core. When the sensor head is over undamaged iron, the meter should read zero if it is calibrated previous to the test for a condition where no fault current is circulating. In actual practice, no insulation system is perfect, and some background signal is usually detected. In addition, the contact resistance of the core to keybar interface is not zero and can be found to vary between near 0 to 2 ohms. This also affects the EL-CID signal that is measured. Usually anywhere from a 0 to ±20 mA EL-CID signal (in quad mode) is found to be normal when good core is measured.

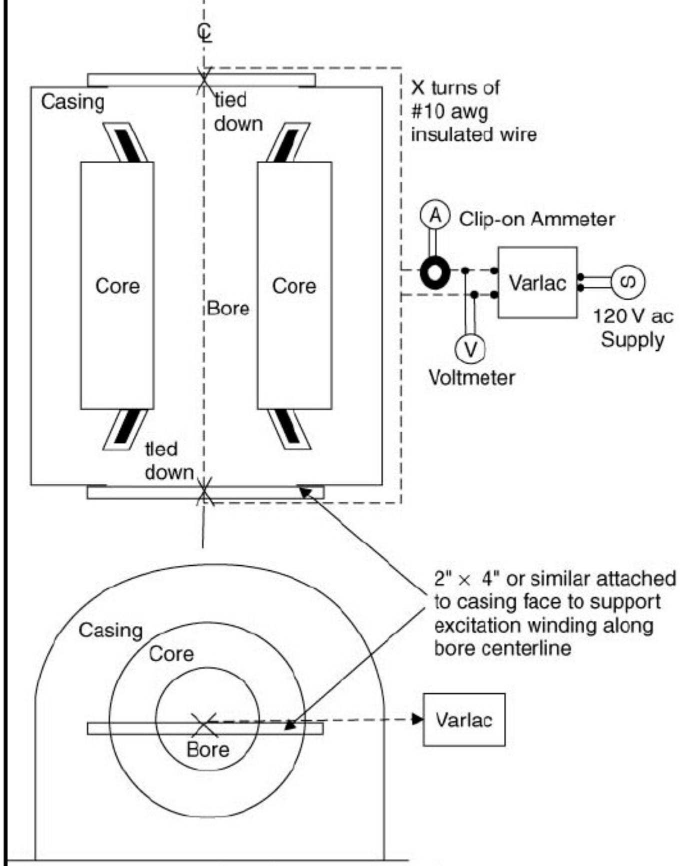

℄
Casing
tied down
X turns of #10 awg insulated wire
Core
Bore
Core
A Clip-on Ammeter
Varlac
S
120 V ac Supply
V Voltmeter
tied down
2" × 4" or similar attached to casing face to support excitation winding along bore centerline
Casing
Core
Bore
Varlac

Fig. 11.3 Excitation winding and power supply setup for EL-CID testing.

EL-CID is somewhat similar to the rated flux test where the undamaged iron slowly heats up producing a background level due to eddy current losses in each laminations. During flux testing, this is recorded as the ambient core temperature rise. Where there is damaged or deteriorated core insulation, the core overheats and is detected as a hot spot above core ambient due to high fault currents circulating locally. In the EL-CID test,

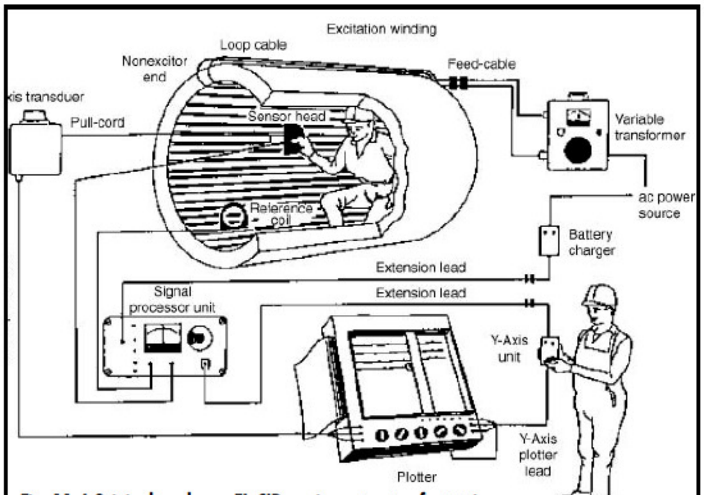


Fig. 11.4 Original analogue EL-CID equipment setup for testing large turbogenerators. (Courtesy of ADWEL International).

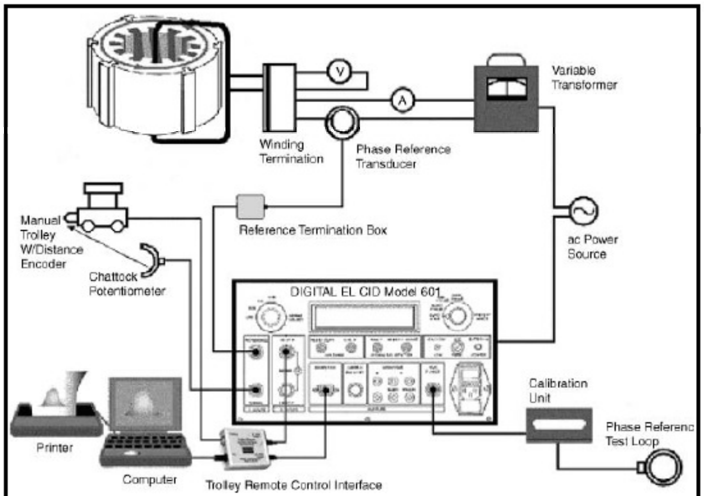


Fig. 11.5 Digital EL-CID equipment setup for testing large turbogenerators. (Courtesy of ADWEL International).

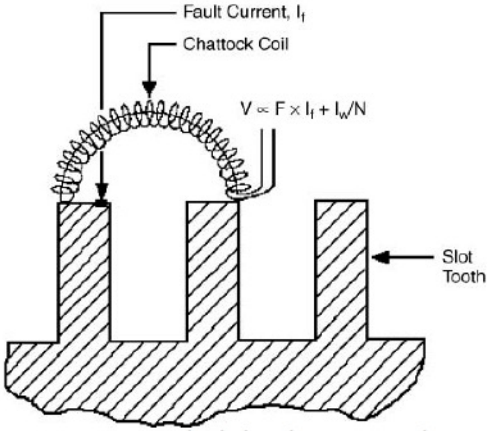


Fig. 11.6 EL-CID sensor head (chattock potentiometer) basic circuit. (Courtesy of ADWEL International).

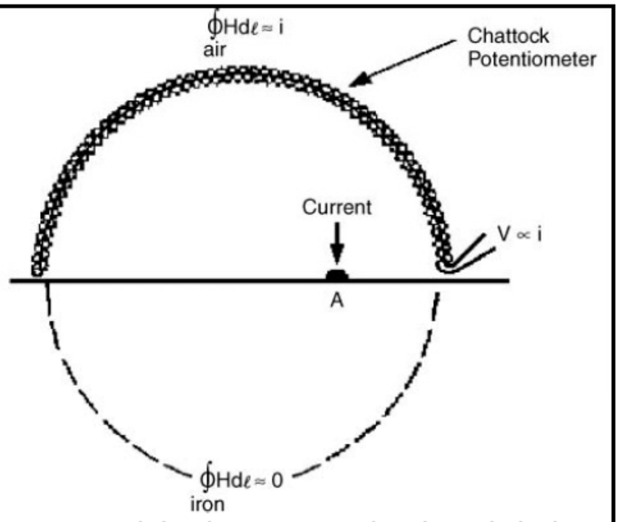


Fig. 11.7 EL-CID sensor coil (chattock potentiometer) winding voltage and induced current is proportional to the current flowing in the fault. The iron portion of the circuit is neglected due its low magnetic reluctance, compared to air. (Courtesy of ADWEL International).

when the sensor head is placed over damaged core areas, the primary indication of a fault is obtained by detecting the flux produced by a current flowing in phase quadrature with respect to the excitation magnetizing current (the phase current). This flux is then converted back to an indicated current (the quad current) assumed to be flowing in the fault (Fig. 11.7). For this reason the quad current detected by the EL-CID processor is frequently referred to as the fault current (although for large faults the phase current may be affected as well, especially where the fault current path is highly inductive). The quad current is indicated on the signal processor meter and the traces recorded on the plotter (original analog EL-CID equipment) or computer (newer digital EL-CID equipment).

EL-CID EXPERIENCE

EL-CID has proved to be extremely reliable in detecting and locating core problems. It can cut the time and manpower required for core testing to within one eight-hour shift, where a flux test may have taken a few days to set up, and then a day to test, and another day to dismantle the test equipment.

In the large majority of the EL-CID tests on turbogenerator machines, experience has been that EL-CID is very reliable in determining that actual core faults or inter-laminar insulation deterioration exists. In other words, if a core defect exists, then EL-CID is likely to find it. Then, if the core is indicated to be defect free by an EL-CID test, there is a very high probability that it actually is free of defects.

Large signals may be found at tooth-top locations on the core, and only indicate a significant surface fault. Local surface faults are generally indicated by faults that show very localized signals, either high or low in magnitude and positive in polarity, if within the test coil span (assuming the standard EL-CID test setup).

Deeper faults can generally be seen over a larger scanning area, and also often become opposite in polarity as the sensor head gets away from the fault area.

This is because the fault is outside the flux path of the chattock coil sensing the fault current, and the magnetic potential difference is reversed.

Figure 11.8 shows a general basic interpretation of the EL-CID signals that can be expected to be seen based on fault location. The magnitudes in Figure 11.8 are only relative to one another to give an idea of what might be expected for faults of roughly the same severity at different locations. The peaks, and widths of the peaks, will vary from fault to fault as their size varies, and as they are more or less severe.

Attempts have been made to correlate EL-CID signal readings to temperatures that would be created in the defect area during a flux test. The basic premise of the EL-CID test significance level of ±100 mA is that this level represents a 5 to 10°C temperature rise, as seen on flux tests, and therefore it is just at the level of temperature rise where most OEMs and experienced stator core experts should carry out repairs to the core iron.

There are a number of issues that makes questionable the assumption that correlates EL-CID's signal to temperature. First, many core testers carry out flux tests at widely differing flux levels. Some prefer to test at 100% of rated flux level, while others test at about the 80% level. Different operators also apply the flux test over widely varying time periods. Yet, by all indications, all seem to work on the same temperature rise criteria. Obviously a 10°C rise at 100% of rated flux is much less significant than at 80% of rated flux. This is so because the 80% level is generally at the knee of the B-H curve and the curve is exponential.

Increasing to 100% when the temperature rise is already 10°C will increase the temperature in the fault.

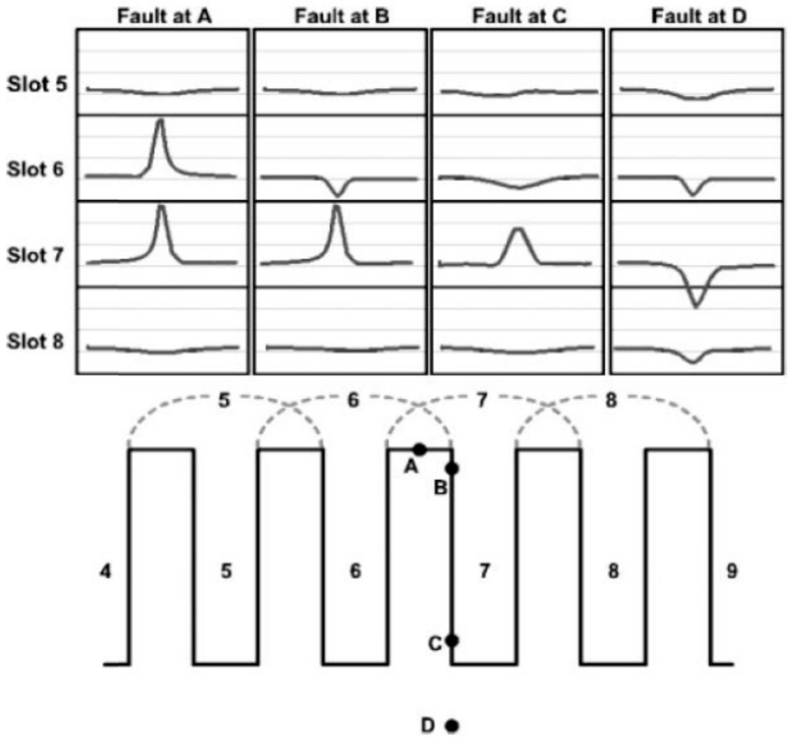


Fig. 11.8 EL-CID signal interpretation of surface and deep faults.

There is also the influence and undetermined significance of core-to-keybar contact resistance at the back of the core. The concern here is that the resistance can be generally measured to vary from nearly 0 to 2 ohms, which will affect the EL-CID signal as well as the temperature measured during the flux test.

For the low flux levels of the EL-CID test, the core-to-keybar contact resistance may be quite significant. This is one of the unknowns for which there is little data one way or another. But it should be noted that on ungrounded cores (i.e., cores with insulated keybars and infinite core to keybar contact resistance), the EL-CID and the flux test are both ineffective unless there are two faults in proximity that allow circulating current to flow and hence be detected by either test. This has been proven by tests done on ungrounded cores, where single faults do not show up until the core is artificially grounded at the back near the keybar behind the location of the fault.

Generally, there is only one keybar that is grounded on such core arrangements (for purposes of the stator ground fault relay), and the testing for single faults is effective in that lamination region only. To test such a core arrangement by either EL-CID or flux test, the core must be purposely grounded at the back, between every keybar, circumferentially, and on every lamination axially. One can easily see the difficulty in this, as this arrangement is not even possible on most stator designs, because of the frame construction. One has to consider this possibility when purchasing a new stator. If a single core fault occurs, then the insulated core may allow operation where the grounded core would fail based on the progression of the fault. However, if two faults occur in the same proximity, then a much more severe fault may occur and go undetected until the effect of the failure causes additional collateral damage, which takes the machine out of service. This is generally a matter of user preference and both philosophies are sound, each in its own way.

In addition there is the problem that core faults can manifest themselves in many forms and levels of severity. It is not uncommon for a surface iron smudge to show a very high EL-CID signal and yet not produce much heat when looked at under infrared in a flux test. The opposite is true as well. It is not uncommon for an EL-CID signal that is not much higher than the manufacturer's recommended significance level to produce significant heat. In particular, with very small faults on the surface where EL-CID does not produce a significant signal, there are sometimes high-spot temperatures detected by infrared, but there is insufficient power to cause damage.

One advantage is that EL-CID can detect deep-seated faults, which may often not show as a particularly large temperature rise on the surface but can be damaging to the body of the core or adjacent conductor bar insulation. This is due to the fact that the attenuation of EL-CID signals is generally less than the attenuation of temperature rises with depth of fault.

The difficulty in correlating EL-CID and Flux test temperatures therefore comes from many issues as stated above and a number of other possible influences as listed below:

- Core-plate grade (i.e., grain oriented vs. nonoriented steels);
- Lamination insulation grades;
- Axial length of the fault;
- Total size of the fault;
- Electrical resistance of the inter-laminar fault (i.e., deteriorated or fretted insulation type damage as opposed to hard-contact, low-resistance type faults);
- Geometry differences in core structure from one machine to another;
- Limitations of the earlier EL-CID test equipment, in relation to the size of the chattock coil itself and the relative size of any fault being measured.

(Current standard Chattock coils have only a 4 mm diameter magnetic sense area, and thus are able to detect very small faults, particularly, if the suspected fault area is investigated/scanned slowly enough.).

All these issues can significantly affect both the observed EL-CID signal and the temperature produced during a flux test. Some are better known and quantified than others. Trying to correlate temperatures to EL-CID signals under so many variables is difficult, unless all of these parameters can be taken into account. In other words, the core under test must be well known to be able to make such a correlation.

There is one other factor regarding EL-CID signal interpretation, and it has to do with readings taken in the phase mode, as opposed to the normal quad mode reading that Figure 11.8 is based on. Basically when a stator has, for example, four turns of an excitation winding and is carrying 12 amps, then it has an excitation level of 48 amp-turns. When the EL-CID signal processor is set to phase mode and a reading is taken from tooth center to tooth center across one slot, a signal of (48 A-T divided by 48 slots) 1 amp should be read. Generally, for most fault areas this is the reading that will be evident. However, in some cases, much higher current is read in the phase mode than the simple magnetic potential based on excitation and slot geometry. One of the things that has been seen when this type of situation occurs is that very high quad readings are often also present, and the fault is usually at the bottom of the slot or in the core yoke area. Correspondingly there is not always much heat given off during flux testing, and the two tests do not always correlate when this occurs. There is very little experimental data on this point, and again it shows that some uncertainties remain in interpretation of EL-CID test results. It is believed that phase readings are also significant and should be factored into the test interpretation. Just what that interpretation should be is unclear to date, due to the difference in faults from case to case.

For the test interpreter probably the main difficulty is when nothing is known about the core under test, nor the type of fault found. The core defect is often not visible, and thus the tester is confounded in trying to determine is how deep it is and how severe it is. The general consensus of the people surveyed on this issue is that more often than not, they cannot tell how severe a detected fault is and must depend on a flux test with infrared scan in making that determination. The ring flux test remains the best test to determine the actual temperature rise of any fault, and whether repairs are required. If the fault is suspected to be deep-seated from the EL-CID test result, the ring flux thresholds should be appropriately adjusted. Once the core is repaired, an EL-CID test can usually show that the repair is successful by the absence of a defect signal. This is perhaps the real benefit of EL-CID testing.

There seems to be general consensus that if an EL-CID test is performed and no damage is found, then the core is defect-free. EL-CID has gained good credibility in its ability to determine and locate the presence of faults, and to verify successful repairs of faults. The general consensus also is that more work is required on EL-CID signal correlation with temperature rise in fault locations.

The general opinion to date is that both the EL-CID and flux testing together are still required to give the best information on any core defect found.

11.2.2 RATED FLUX TEST WITH INFRARED SCAN

The rated flux test is a high-energy test used to check the integrity of the insulation between the laminations in the stator core. It is also commonly referred to as the ring flux test, in which near-rated flux (normally about 80%) is induced in the stator core yoke. This, in turn, induces circulating currents and excessive heating in areas where the stator iron is damaged (Fig. 11.2). The heat produced is detected and quantified using established infrared techniques.

Flux is produced in the iron by looping a cable around the core in toroidal fashion (Fig. 11.9), and circulating a current at operating frequency. The flux required for the flux test is half the normal operating flux due to the difference in the way the flux is induced in operation (Fig. 11.10) from that of the flux test.

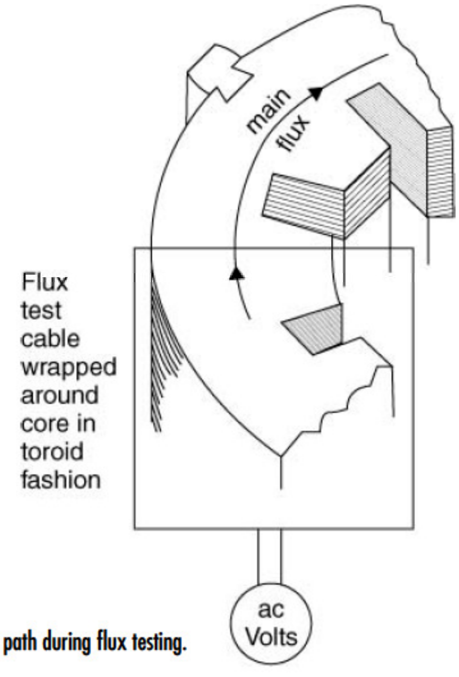


Fig. 11.9 Flux path during flux testing.

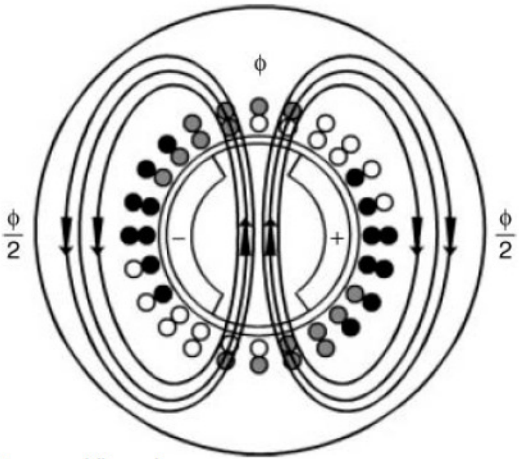


Fig. 11.10 Operational flux path.

The power supply for the cable is usually taken from two phases of one of the high-voltage breakers (i.e., 4 kV) in the plant, or a portable motor generator set.

The correct number of turns are looped around the core to produce the required level of flux. IEEE Std 432 [11] provides the following expression to find the rated volts per turn required on the stator core:

$$\text{Voltage per turn of test coil} = \frac{1.05 \times V_{\text{LL}}}{2\sqrt{3} \times K_{\text{w}} \times N}$$

where
VLL = line-to-line voltage
Kw = winding factor
N = number of turns per phase in series in the stator winding

As the equation shows, the available power supply voltage is divided by the calculated volts per turn above, to give the correct number of turns to loop through the core. If the number of turns includes a fraction, then the next highest number is used, to reduce the flux level to below 100% or below rated. Using too high of a flux level can create core damage, since there is no cooling on the core during the test.

Once the number of turns is known, the current capacity is required to size the cable and ensure the power source can handle the current that will be drawn.

Knowledge of the specific B-H characteristic of the subject core being tested is required for this. It cannot be stressed enough that the exact B-H characteristic of the stator core should be known in relation to the flux volts per turn as well as the current required from the power source (Fig. 11.11). In many instances it is unknown, and therefore the number of ampere-turns required must be estimated based on industry curves for the most likely grade of core-plate that will be used in the machine under the test. A higher end and lower end core-plate grade are usually selected to provide a range of possible operating characteristics for the subject core. These are selected to provide a range of possible excitation requirements, based on B-H curves taken from small and large turbogenerator applications.

From the winding configuration for the subject generator, the power supply available, and the B-H curves, an estimate can be made for the number of turns required to achieve the required level of flux for the test. This is generally in the 70 to 90% range of rated flux. The current that would be flowing in the flux cable will depend on the actual B-H characteristic of the stator iron and therefore, this must be carefully estimated for safety of both personnel and the equipment. When the B-H curve is in doubt, adding a higher number turns will reduce the level of flux. Then it follows to successively remove turns and keep recording the current attained as the flux volts per turn increases. Successive voltage application in this manner can be made until a B-H curve is created and the proper number of turns found (Fig. 11.11).

The flux test is set up as basically shown in Figure 11.12. The power supply is selected and connected as shown. The cable is wound through the stator bore the correct number of times, and connected back to the power supply. Protection for the test cable is set up to provide "ground fault" and "overcurrent." The stator core, frame, and windings were all grounded for their protection and that of the test personnel. The CTs should also shorted at the terminals and grounded.

Fig. 11.11 B-H curve example showing the flux volts per turn, the percentage of rated flux, and the number of turns versus supply current.

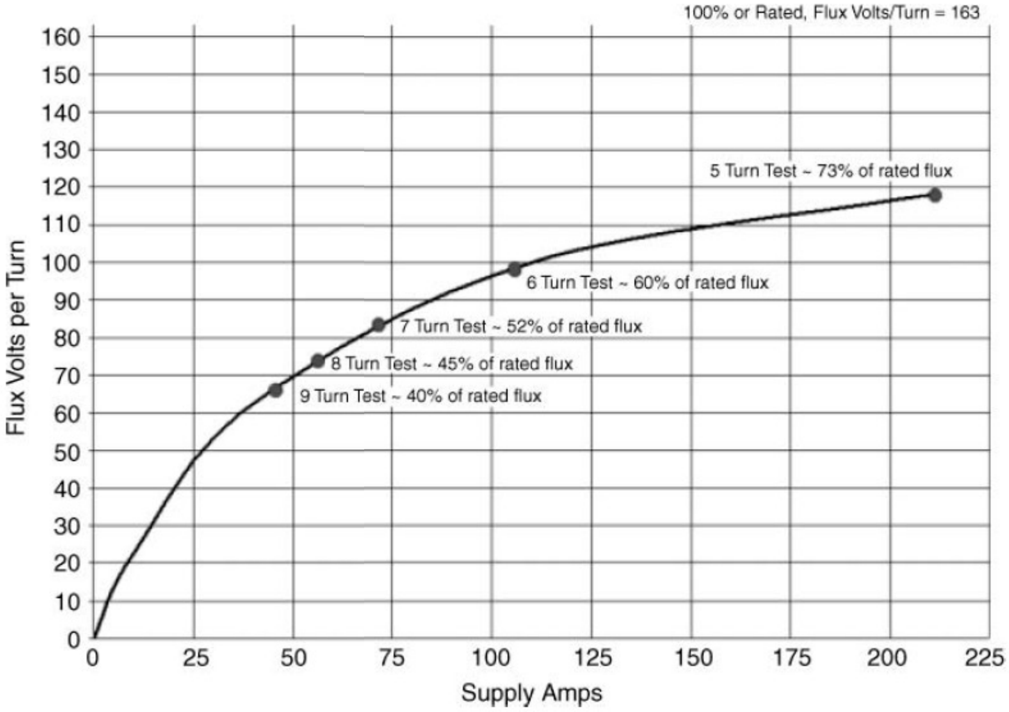
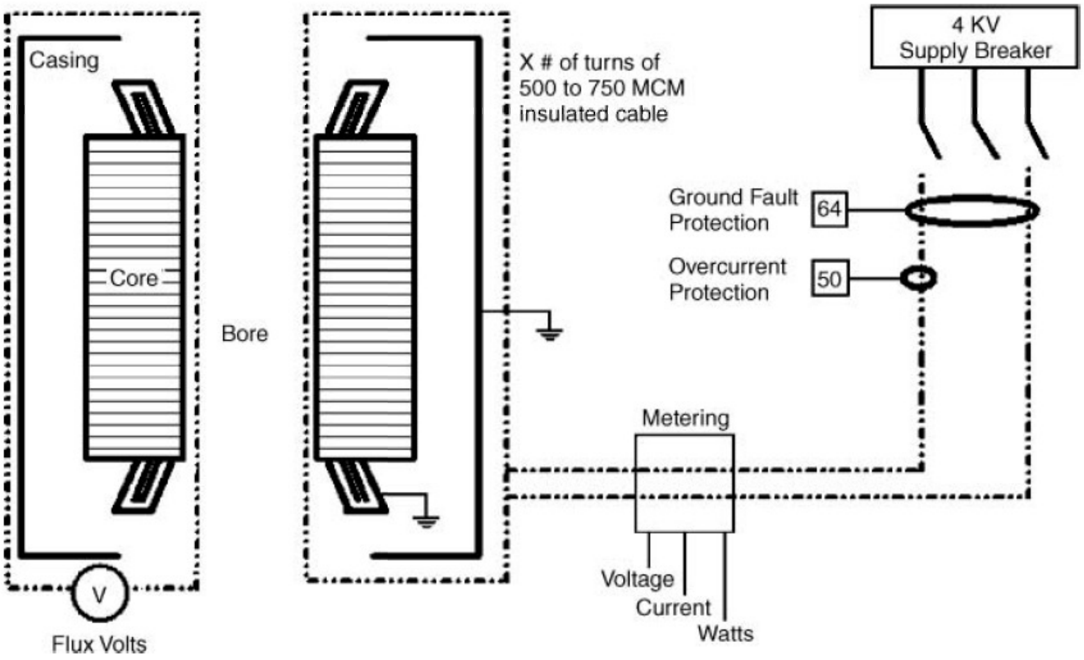


Fig. 11.12 Stator core, excitation, and protection setup for a flux test of a large turbogenerator stator core.



Metering is set up to provide measurements of supply voltage and current. A single loop of cable is installed additionally to measure the actual flux volts on the stator core during the test. This is done to provide an accurate measurement of the induce voltage across the core and the level of flux as well.

In some cases an infrared, nonreflecting mirror is used to monitor the temperature of the stator core when angled viewing from outside the stator bore is difficult (Fig. 11.13). The mirror provides a known surface to accurately measure the temperatures so that the absolute and relative rise of temperatures in the core defect areas can be recorded.

Once the flux is established in the core, it is kept for at least 30 minutes to 1 hour. The temperature of the core should be maintained within values not significantly higher than those encountered during operation. Under these conditions, the temperature rises in the core are monitored and recorded while the existence of hot spots is investigated with infrared monitoring equipment (and possibly a nonreflecting mirror) (Figs.11.14 to 11.16).

The temperature rises of the “good” core areas (ambient core temperature rise) are then compared to the temperature rise profile of any defective locations found. Once the defects are located and characterized, repair solutions can then be addressed.

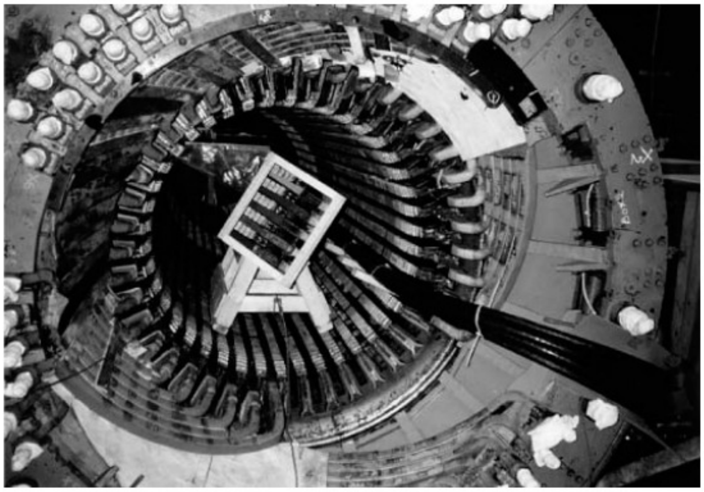


Fig. 11.13 Stator core excitation setup for a flux test of a large turbogenerator stator core, with nonreflecting mirror for infrared applications.

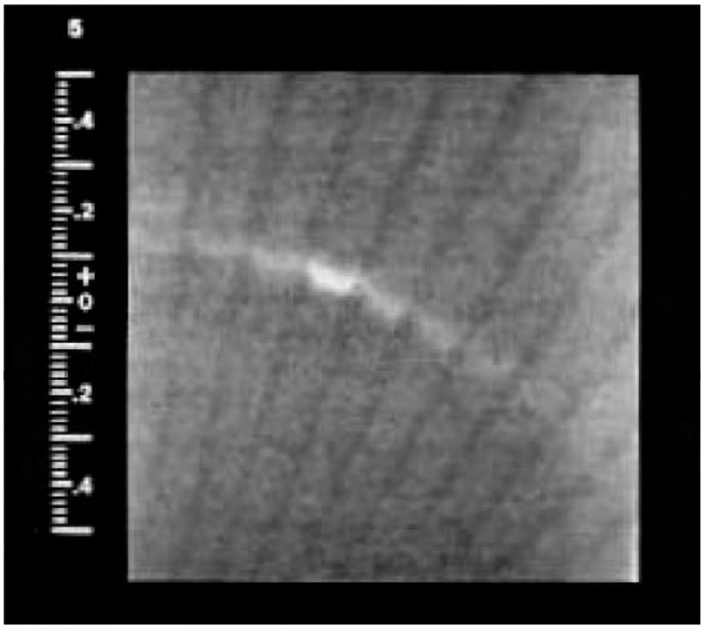


Fig. 11.14 Flux testing with direct infrared scanning of a core hot spot in the stator bore.

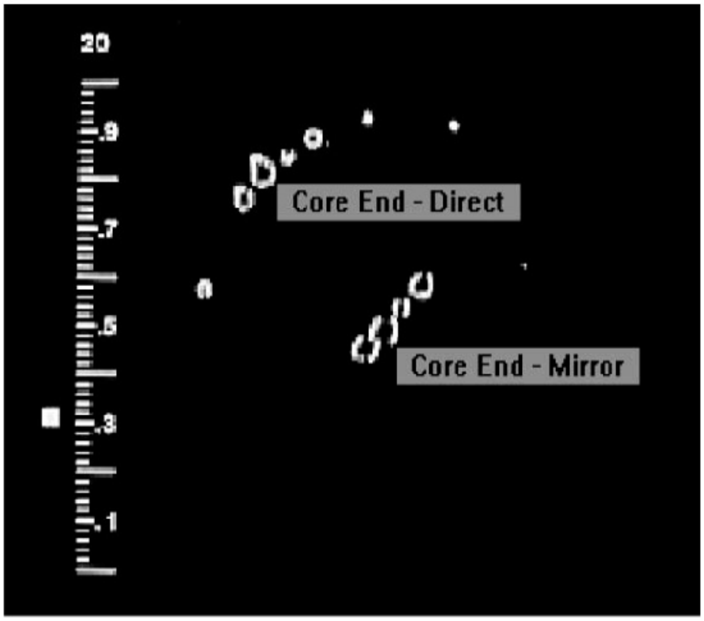


Fig. 11.15 Four core-end hot spots as seen in the non-reflecting mirror and directly, using an isotherm level to measure the temperature of the defects.

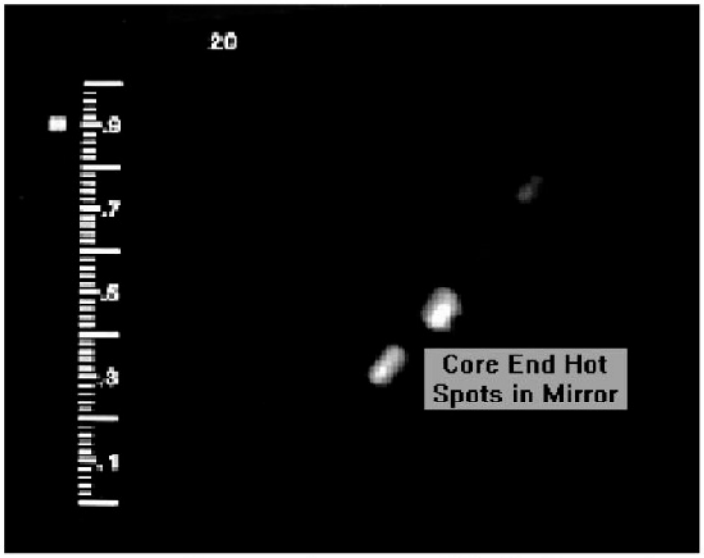


Fig.11.16 Same core-end hot spots seen by zooming in with the infrared camera on the nonreflecting mirror.

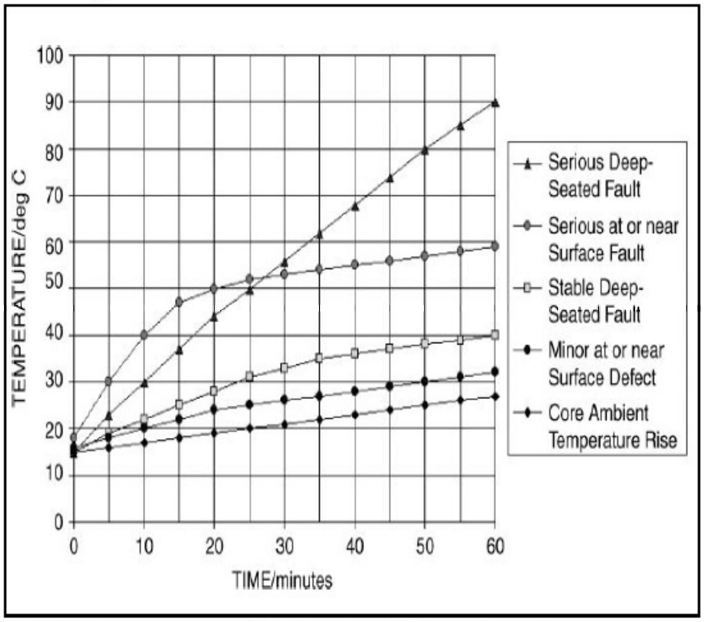


Fig. 11.17 Temperature rise profiles of typical core fault types during flux testing with infrared scanning.

11.2.3 CORE LOSS TEST

Stator core loss is a function of terminal voltage. The open circuit saturation curve for the core iron determines it. The core loss for any particular generator is always determined at the factory by the manufacturer, and is not a test that is generally done at site.

The core loss is determined by the generator being coupled to, and driven by, a calibrated motor. The friction and windage (mechanical) losses are calculated and separated out from the electrical losses to provide a value of core loss for the stator [7].

If there is suspected wear of the inter-laminar insulation in the core, on a large scale, it may be possible that a core loss test could be done to compare the present value to the "as new" value to determine the extent of deterioration occurring. However, the serious challenge of driving the generator at site with a calibrated motor, for all practical purposes, limits this test to the OEM's factory.

11.2.4 THROUGH-BOLT INSULATION RESISTANCE

There are a few manufacturers that provide through-bolts in their stators to pull the cores tight. These through-bolts are full-length bolts inserted axially through the core through holes in the core iron. There are many of them located symmetrically around the circumference of the core, a few inches below the stator winding slots. The ends are threaded and terminated at each end through a pressure plate, where a nut is installed to maintain compression after the core is pressed to a few hundred psi.

The entire through-bolt assembly is insulated generally by cured epoxy/glass tape wrap or a phenolic tube through the core, and an arrangement of insulators at the pressure plates and nuts. This is done to ensure that the through-bolts do not create any short circuits across the stator core laminations and cause a core failure by circulating currents.

To ensure that the insulation is in good condition, the insulation resistance of the through-bolts is checked by meggering at 500 V DC. A good reading should be in the hundreds of MO range.

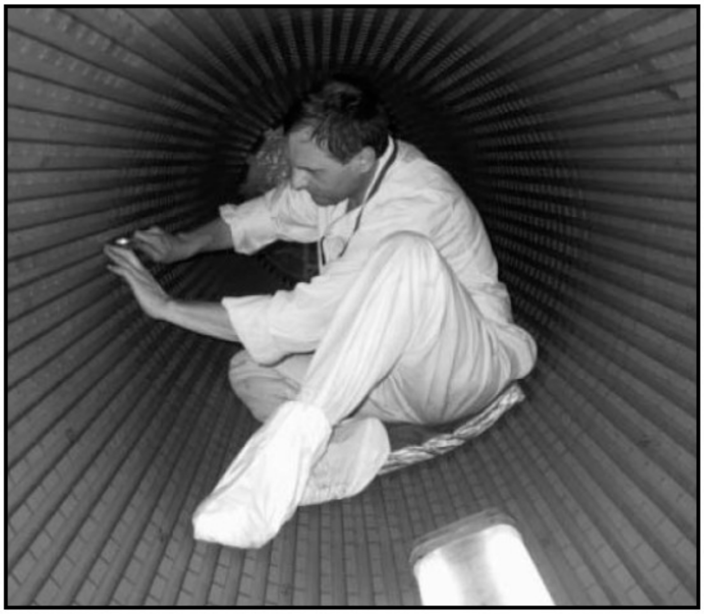


Fig. 11.18 Stator winding wedge tightness testing by manual tapping method.

11.2.5 INSULATION RESISTANCE OF FLUX SCREENS

Most large generators are provided with some form of flux screening for the stator core-end. This is to prevent overheating in the core ends due to stray flux from the stator end winding. When flux screens are used, they are insulated from the core end to ensure that no additional circulating currents flow between the core and the flux screens, which would create additional unwanted heating in the core-end.

To ensure that the insulation is in good condition, the

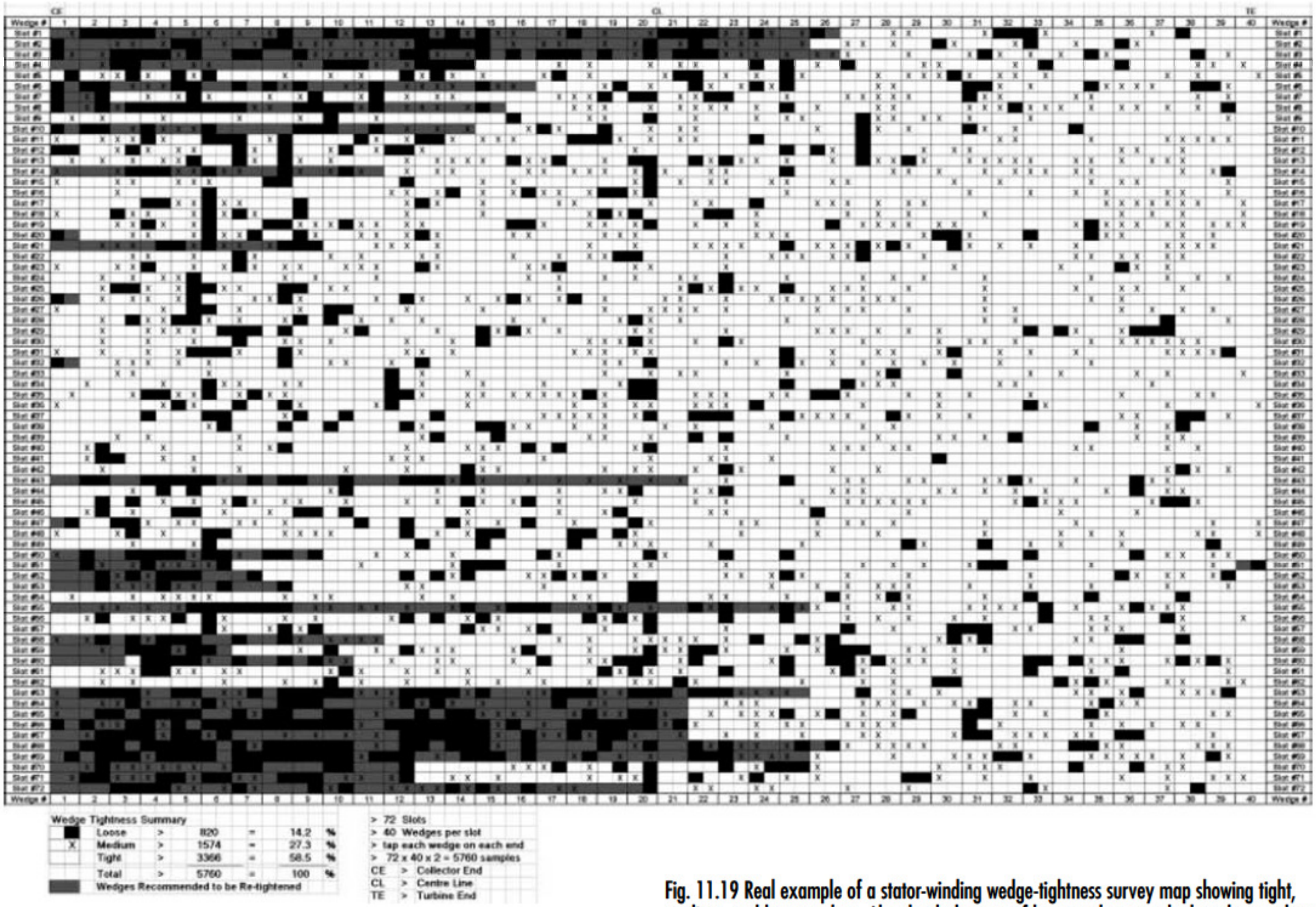


Fig. 11.19 Real example of a stator-winding wedge-tightness survey map showing tight, medium, and loose wedges. Also the dark areas of loose wedges are shadowed over where re-wedging during an outage was recommended and carried out.

insulation resistance of the flux screens is checked by meggering at 500 V DC. A good reading should be in the hundreds of mega-ohms range.

11.3 STATOR WINDING MECHANICAL TESTS

11.3.1 WEDGE TIGHTNESS

Loose stator winding wedges allow the stator winding in the core slots to move because of electromagnetic bar bounce forces and vibration. This can in turn cause the ground-wall insulation of the winding to wear and fret against the stator core iron and eventually fail by ground fault. Therefore it is necessary to maintain the stator winding wedges tight to avoid such problems.

Checking wedge tightness is done by tapping with a suitable hammer (i.e., an 8 oz ball peen) and recording the degree of looseness on a chart (Figs. 11.18 and 11.19). During the tapping, the wedge should be checked by tapping along its full length and feeling for the vibration as well as listening to the sound produced. Tight wedges will have very little vibration and a hard ringing sound. Loose wedges will noticeably vibrate and have a very hollow sound. Wedges with vibrations and sounds in between these indicate that the wedge is in the process of becoming loose. It requires a trained ear and feel to determine the degree of looseness in wedges of various machines because not all wedging systems are alike and they do not all sound and feel the same.

The criteria for determining when re-wedging is required is well established, with some variation from one manufacturer to another, and from one operator to another. However, the following is the accepted rule-of-thumb.

Re-wedging in a particular slot is required if:

1. Less than 75% of the wedges are tight in the slot
2. Three or more adjacent wedges are fully loose
3. Fully loose end-wedges must be re-tightened.

Since the early 1980s there have also been automated systems developed for wedge-tightness testing. Such devices mechanically stimulate the wedge being tested and record the vibration produced from it. With some modern devices (Fig. 11.20), the vibration results are input to a computer and a map is produced.

Once a wedge-tightness survey is performed, it is always a good practice to record the tightness for successive surveys of the machine, so that an estimate can be made of when tightening should be done. The individual surveys of a machine should also be compared to other identical machines in a multi-unit station, since they do not always loosen at the same rate. This can be seen in an actual example shown in Figure 11.21, taken from a four-unit station with identical machines, where three of four generators tended to loosen at the same rate while one loosened much quicker.

11.3.2 STATOR END-WINDING VIBRATION

High vibration on the stator end-winding can cause premature winding failures.

Acceptable vibration limits may vary from one manufacturer to another. Generally, however, a good rule is to keep the maximum vibration to less than 50 ºm (~2 mil) peak to peak (unfiltered), with no natural resonance within the frequency ranges 50-75 Hz and 100-140 Hz for 60 Hz units or about 40-65 Hz and 80-120 Hz for 50 Hz units (similar to the stator core and frame limits). When in doubt, it is best to contact the OEM for a recommendation on vibration limits.

Measurements are accomplished by vibration transducers mounted on the coil heads or stator bar connections at each end of the machine. Mounting is done in such a way that the transducers are insulated from, and noninvasive to, the electrical circuit of the winding. The transducers should be capable of radial and tangential vibration measurements.

If permanent mounting is not possibl, another method is to carry out an impact frequency spectrum analysis of the end-winding. This is done with temporary vibration transducers mounted on the end-winding and a calibrated impact hammer to measure the vibration signatures.

This test is also known as a "bump" test.

As in the stator core and frame, end-winding vibration problems are very difficult to diagnose and expensive to fix. They should also be addressed on a machine-to-machine basis, as each case will present a unique situation.

11.4 WATER-COOLED STATOR WINDING TESTS

11.4.1 AIR PRESSURE DECAY

The pressure decay test is probably the oldest test method for detecting leaks. The stator winding is first completely dried out internally, and then pressurized up to the level of the generator operating hydrogen gas pressure. This provides a very high pressure differential and a leak direction that is normal to the

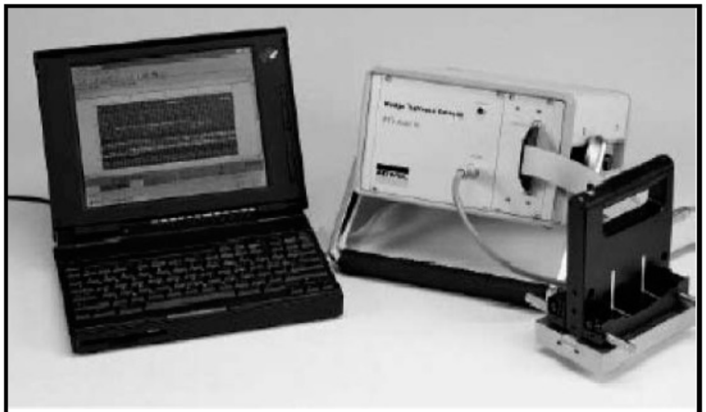


Fig. 11.20 Automated testing and mapping system. (Courtesy of ADWEL International

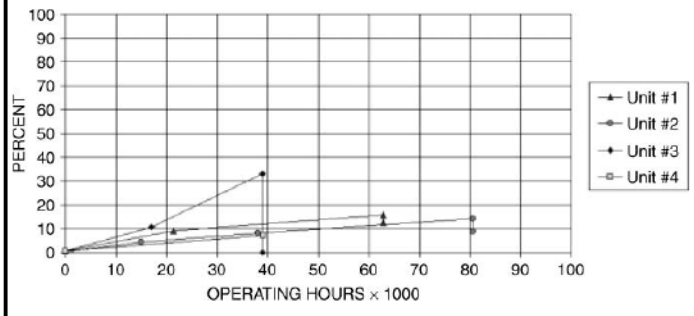


Fig. 11.21 Stator-winding wedge-looseness profile record over time. This shows the difference between four supposedly identical machines and that they do not necessarily loosen at the same rate.

operating leak direction.

When pressurized to levels as high as the operating hydrogen gas pressure, a 1 psi pressure drop will only correspond to about 1 cu ft loss of volume. This test is therefore not sensitive to small leaks and highly dependent on atmospheric conditions of temperature and barometric pressure. It is carried out by pressurizing the stator winding to about 30 psi and watching that the drop in pressure over a 6 hour period does not exceed 0.1 psi. To recognize smaller leaks, the test must be carried out over a period as long as 24 hours using very accurate and calibrated pressure gauges.

During pressurization, "snooping" is also used to identify leaks. This technique entails application of a soapy water solution to the winding in selected areas. It is generally used at joints, fittings, and points that are likely sources of leaks.

If a leak is present, the soapy water will bubble indicating that the tracer gas is escaping at the bubble location.

Another method of detecting leaks is to use an ultrasonic probe to listen for the sound created by the leaks (Fig. 11.22).

11.4.2 TRACER GASES

Freon gas was, at one time, the preferred gas for leak tracing and snooping. Due to environmental factors, Freon has been superseded by the use of helium gas.

Helium is a light gas, which is molecularly small in size making it ideal for this application. In addition, it is nontoxic and non-hazardous.

The trace method involves pressurizing the stator winding with helium, or a mixture of air and helium. A portable helium gas detector is then used to "sniff" over the external surfaces of the exposed portions of the stator winding for sources of helium. Obviously this method requires access to the generator internals, and even so, it is still not possible to cover the entire winding by this method. Therefore it is only one of the tests that are required to fully identify leak problems and locate the source.

The helium tracer technique has been shown to be very successful in pinpointing stator winding leaks.

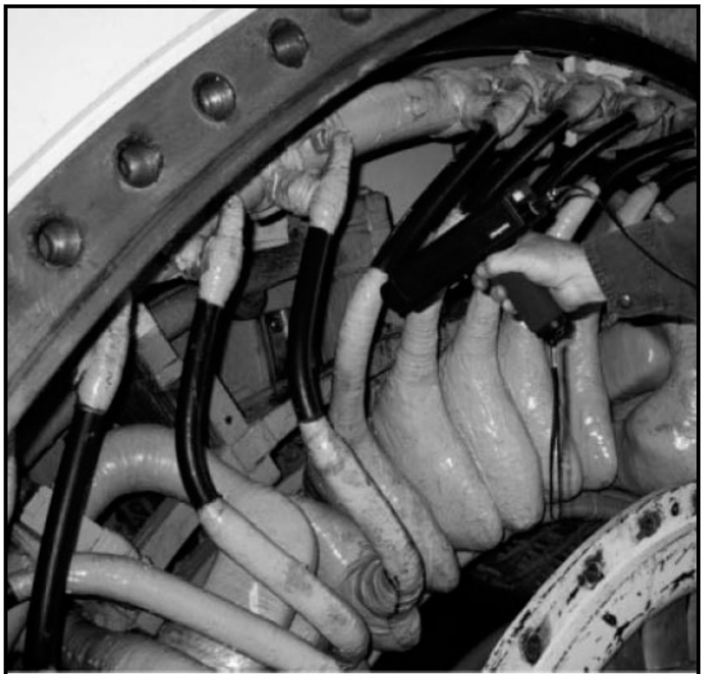


Fig. 11.22 Ultrasonic probe used to detect sound from air pressure test leaks.

11.4.3 VACUUM DECAY

Vacuum decay testing is very sensitive compared to pressure decay testing. It is generally used to determine the leak sensitivity of the entire winding. This test has the advantage that it is relatively insensitive to atmospheric conditions of temperature and to barometric pressure. Further it only requires a few hours on test to determine the leak rate, since vacuum gauges are far more sensitive than pressure gauges. The test leak direction is opposite to the operating leak direction of water but normal to the operating leak direction of hydrogen into stator cooling water (SCW). Even the smallest leaks will be detected by this method. The test is carried out by pulling vacuum to 29 inches of mercury, and watching that the vacuum gauge does not drop in vacuum by more than 0.2 inches Hg over 6 hours.

11.4.4 PRESSURE DROP

The differential pressure across the stator winding from the stator cooling water inlet to the outlet of the generator can also be tested in the off-line mode to ensure that the design pressure drop across the whole stator winding is at the correct level. Alternatively, each individual stator bar can be pressure-drop tested to estimate the stator cooling water flow rate in each bar, and ensure that it is above the minimum recommended level for adequate cooling of the stator winding.

11.4.5 FLOW TESTING

Flow checks are generally done on individual bars to determine if there are restrictions in the cooling water path. Both air and water have been used to accommodate this test, but it is usually done with water. The actual flow in each stator bar is measured to compare it to the design level of flow required for the particular machine being tested. Some flow checks are made using ultrasound techniques to monitor the flow rates. Low flow bars are then noted for corrective action such as backflushing or chemical flushing.

11.4.6 CAPACITANCE MAPPING

Capacitance mapping is a nondestructive electrical test method used to identify the presence of moisture in the groundwall insulation from stator winding leaks.

The technique is based on the difference in dielectric constant of the ground-wall insulation and that of water. All top and bottom bars are tested at both ends of the machine, providing an average measurement of capacitance. The measurement is made by a capacitance probe placed on the side of each bar. Good insulation is indicated by measurements falling within ±2 standard deviations from the average. Measurements of capacitance greater than +3 standard deviations are considered suspect, and those greater than +5 are generally found to be wet and to fail their subsequent electrical tests. Failure of this test tends to indicate that the stator bar is not suitable for long-term service.

Care must be taken when performing this test, since the capacitance measurements are also sensitive to the application of the capacitance probe, bar surface condition and coatings, grading paints, and the condition of the ground-wall insulation itself.

11.5 STATOR WINDING ELECTRICAL TESTS

Stator windings are comprised of materials with specific resistive and dielectric qualities. The materials used comprise: mica, Dacron tapes, glass tapes, asphalt binders, polyester resins and epoxy resin binders, and so on. There are also insulating, resistive, and stress grading paints applied to various portions of the winding to ensure controlled distribution of the voltage on the individual stator conductor bars. All of the materials used, and their application, are done in such a manner as to ensure proper functioning and a reasonable degree of long term reliability of the winding. The stator winding insulation system is complex and requires a variety of tests to establish its present condition and expected long-term reliability. Therefore, to fully test the stator winding, so that the best possible determination of the winding condition can be made, it is desirable to perform both AC and DC tests.

The DC tests are generally sensitive to the presence of cracks, moisture, particle contamination, or a general degradation of the electrical creepage path. During DC application, the voltage is divided according to the DC leakage resistance.

Basically, DC is used to test the conductivity of the insulation system. The DC testing has the advantage that it less damaging to the insulation due to the absence of corona and partial discharges associated with AC.

The AC testing, on the other hand, applies the more realistic electrical stress to the winding, since it operates ac when in service. When the AC test voltage is applied, it is actually applied across several dielectric components of the winding insulation, which are effectively in series. Therefore, the leakage current must go through each of the dielectrics until it reaches ground potential. Under AC, the voltage is therefore divided according to the relative permittivity of each of the dielectric materials.

The AC testing is in fact far more searching than DC. In addition to the conducting properties of the insulation, AC testing is also capable of determining the loss or power factor characteristics and the dielectric properties. In addition the mechanical integrity of the insulation can be also be alluded to by the capacitance characteristics of the winding in terms of insulation de-lamination.

As with many other issues about testing insulation of large electric machines, experts and operators have different opinions about which one of the two tests (DC and/or AC) is more convenient. Some only prefer DC tests, while other prefer AC testing. Still, others like to use both.

11.5.1 PRE-TESTING REQUIREMENTS

If the stator winding is water cooled, it must be completely dried prior to all testing to obtain meaningful results. If there is stator cooling water left in the winding, it will alter the test results and give a distorted picture of the insulation condition.

All three phases must be isolated to ensure that all testing is carried out on the stator winding only. This means that each phase should be completely separated at the neutral point and floated from ground. The line ends of the stator winding should be separated from the isolated phase bus (or cables, in smaller units) just outside the generator, at the stator terminals.

The generator current transformer windings should be shorted and grounded to avoid induced high voltage and possible discharge failure of the insulation.

All instrumentation leads should be grounded to also avoid induced high voltage and possible discharge failure of the insulation.

Before conducting any high-voltage testing of the unit, consult vendor and/or pertinent standards.

11.5.2 SERIES WINDING RESISTANCE

This test is used to measure the ohms resistance of the copper in each phase of the stator winding. Given the relatively low DC series resistance of windings of large machines, the measurement accuracy requires significance to a minimum of four decimal places.

The purpose of the test is to detect shorted turns, bad connections, wrong connections, and open circuits. Acceptable test results consist of the three resistance values (one per phase) to be balanced within a 0.5% error from the average.

The test is very sensitive to differentials of temperature between sections of the winding. The machine should be at room temperature when the test is performed.

As with any other electrical test, the results should be compared with original factory data, if available. This test can be performed on stator and rotor windings.

11.5.3 Insulation Resistance (IR)

The purpose of this test is to measure the ohmic resistance between the conductors in each of the three-phases and ground (i.e., the stator core). This test is generally regarded as an initial test to look for gross problems with the insulation system, and to ensure further high-voltage electrical testing may “relatively” safely continue, in terms of danger of failing the insulation.

Normally the measurements of IR will be in the megaohm range for good insulation, after the winding is subjected to a DC test voltage usually done anywhere from 500 to 5000 V, for one minute. The minimum acceptable reading by IEEE Standard 43 [4] is (VLL in kV + 1) M©. The test is carried out with a megger device. However, resistance bridges may also be employed.

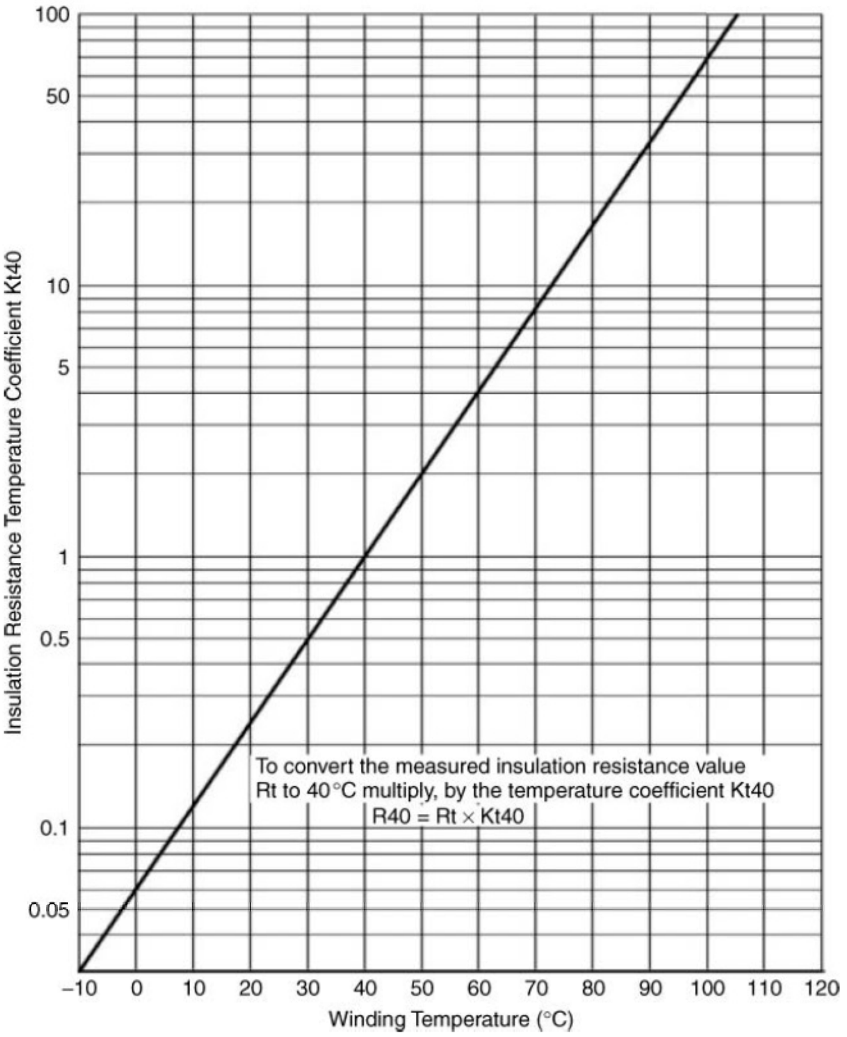
The DC test voltage level is usually specified based on the operating voltage range of the machine, the particular component of the generator being tested, operator's policy and previous experience, and knowledge of the present condition of the insulation in the machine. Although the readings obtained will be somewhat voltage-dependent, this dependency becomes insignificant for machines in which the insulation is dry and in good condition. It is essential that water-cooled stator winding be completely dried before any testing so that any poor readings will be due to a “real” problem, and not to residual moisture from the stator cooling water.

The readings are also sensitive to factors like humidity, surface contamination of the coils, and temperature. Readings should be corrected to a base temperature of 40°C by the following:

$$R\ (40^{\circ}\mathrm{C}) = K \times R_{\mathrm{measured}}(^{\circ}\mathrm{C})$$

Insulation resistance tests are performed on both stator and rotor windings, core endflux screens, and core compression or through-bolts as mentioned previously.

The insulation between the core-end flux screen and the stator core-end iron ensures that the flux screen maintains its capability to shield the core-end from axial flux, and keep the resulting circulating currents within the flux screen, without providing a current path to the core.



To convert the measured insulation resistance value Rt to 40°C multiply, by the temperature coefficient Kt40
R40 = Rt × Kt40

Fig. 11.23 Insulation resistance versus winding temperature curve. (Courtesy of EPRI).

The insulation between core-compression bolts and the iron keeps the throughbolts from short-circulating the insulation between the core laminations. Otherwise, large eddy currents generated within the core would produce heat and temperatures, which could further damage the inter-laminar insulation, as well as the insulation of the windings. Figure 11.24 shows typical IR behavior as a function of time.

11.5.4 POLARIZATION INDEX (PI)

Insulation resistance is time-dependent as well as being a function of dryness.

The amount of change in the IR measured during the first few minutes depends on the insulation condition, and the amount of contamination and moisture present.

Therefore, when the insulation system is clean and dry, the IR value tends to increase as the charge is absorbed by the dielectric material in the insulation.

When the insulation is dirty, wet or a gross insulation problem is present, the charge does not hold, and the IR value will not increase because of constant leakage current at the problem area. Therefore the ratio between the resistance reading at 10 minutes and the reading at 1 minute produces a number or "polarization index" which is essentially used to determine how clean and dry the winding is (Fig. 11.25).

Class B and F windings tend to show higher PI values than windings made of class A insulation. It is also dependent on the existence of a semiconducting layer.

$$K = 0.0635 \times \exp(0.06895 \times T_{\text{measurement}}(\text{in } ^{\circ}\text{C})$$

The recommended minimum PI values are as follows:

Class A insulation: 1.5
Class B insulation: 2.0
Class F insulation: 2.0

The same megger used for the IR readings should be used to determine the PI. The PI readings should be done on a per phase basis at the same voltage as the IR test, and can be used as a go/no-go test before subjecting the machine to subsequent high voltage tests, either AC or DC. The IR readings for the PI test should also be corrected to 40°C as in the IR test. Performing the high-voltage tests on wet insulation may result in unnecessary failure of the insulation.

11.5.5 DIELECTRIC ABSORPTION DURING DC VOLTAGE APPLICATION

Dielectric absorption current characteristics can be used to measure the aging of the resin binder in the ground-wall insulation. When applying DC voltage to insulation material, a time-dependent flow of current is established. This current has a constant component, called the conduction current or leakage current, and a transient component, called the absorption current.

Absorption current is a function of the polarization of the molecules in the binding

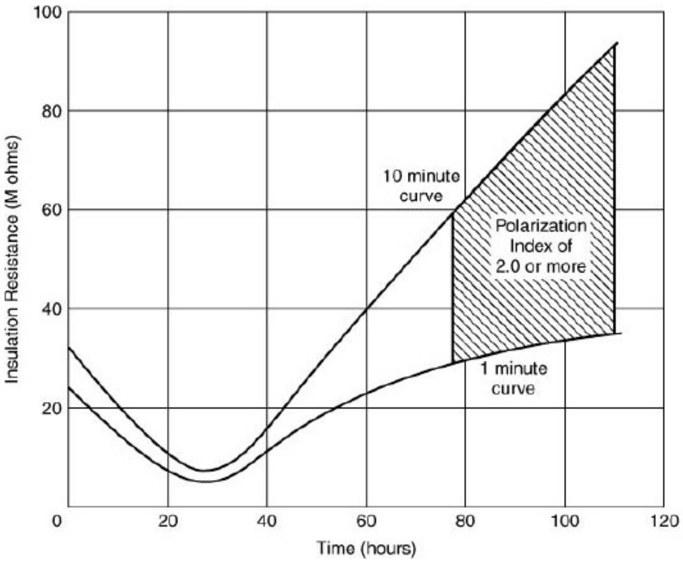


Fig. 11.24 Insulation resistance as a function of time and dryness. (Courtesy of EPRI).

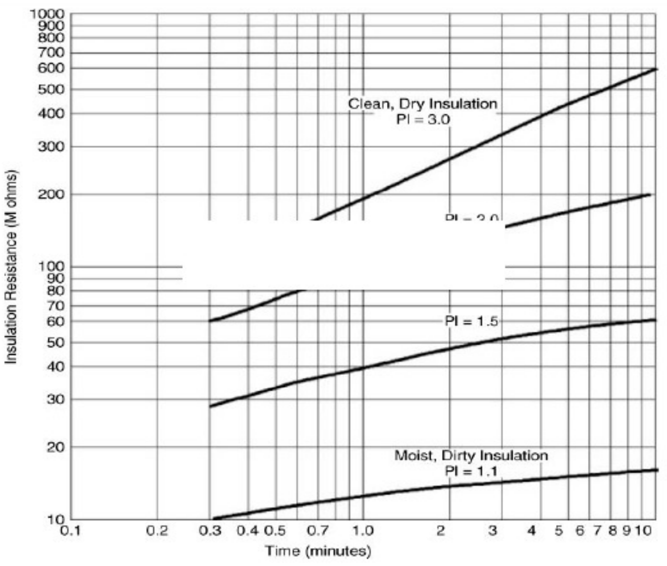


Fig. 11.25 Polarization Index curves for insulation resistance as a function of time. (Courtesy of EPRI).

material. The older the binding material, the more polarized it becomes, and the more absorption current flows. Therefore this test is best used as a comparison test between the winding condition at different times, and between similar windings.

Absorption current is also temperature dependent. This fact should be taken into consideration when performing the test and interpreting the results.

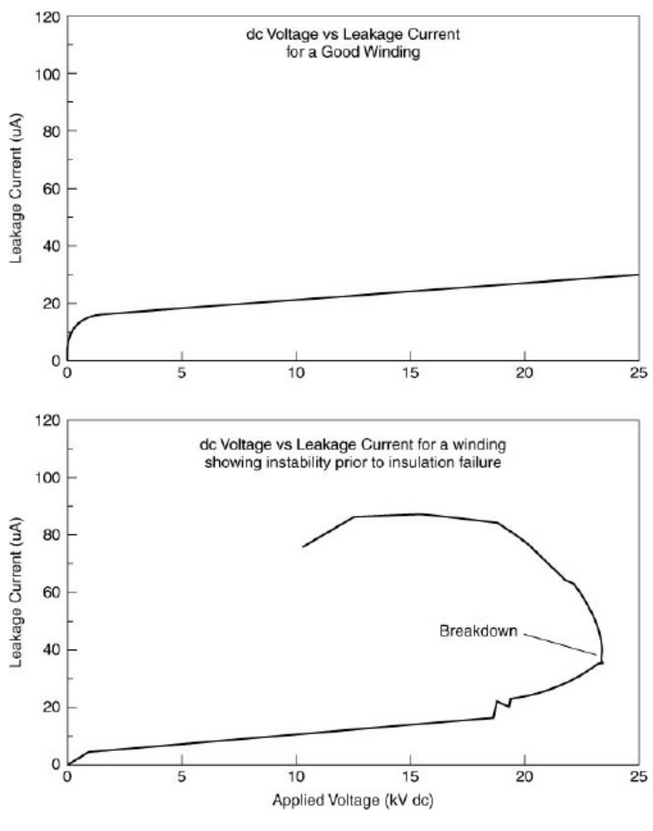


Fig. 11.26 DC Ramp test plot. (Courtesy of EPRI).

Absorption current is also dependent on the amount of voids in the insulation.

The dependence is inverse, meaning an increase in the number of voids in the insulation will tend to reduce the magnitude of absorption current. The contradictory effects regarding voids density and aging of the binding material renders this test difficult to interpretation. It is best when used in conjunction with other dielectric tests, such as partial discharge and dissipation factor tip-up tests.11.5.6 DC Leakage or Ramped Voltage

The DC leakage or ramped voltage test is a controlled DC voltage application designed to test the winding in such a manner as to monitor the DC leakage current, at the same time the DC voltage is increased. The leakage current is plotted against the DC voltage applied to give early warning of any impending insulation breakdown. This helps in limiting damage by shutting down the test prior to a full breakdown occurring (Fig. 11.26).

When DC voltage is applied to the winding, a time-dependent flow of current is established. This current has a constant component, called the conduction or leakage current, and an initial component, called the charging or absorption current.

Therefore it is advisable to raise the voltage to the first level of the kV/min rate, hold for 10 minutes to get beyond the charging phase of the voltage application, and test while dealing primarily with the leakage current. This way the charging current influence on the leakage current rate of rise will be minimized.

The final DC test voltage level is generally in the range of 125 to 150% of (VLL °- 1.7) kV dc (ANSI Std C50.10). The value actually chosen between 125% up to 150% of the test voltage is dependent on the age of the machine insulation, and knowledge of its general condition.

The ramp rate is selected at 3% of the final test voltage level in kV /DC/minute (IEEE Std 95). The ramp rate usually is in the range of 1.5 to 2 KV per minute.

Generally, the ramping portion of the test is automated to allow a steady increase in the voltage. A DC hi-pot set with the capability of a timed and steady voltage increase is required. If this is not possible with the equipment available, then a basic DC hi-pot set can be used to raise the voltage in the pre-determined 3% voltage steps, holding each step for 1 minute.

11.5.7 DC HI-POT

The DC hi-pot test is used to ascertain if the winding is capable of sustaining the required rated voltage levels (without a breakdown of the insulation), with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying high voltage to the winding (the three phases together, or one at a time, with the other two grounded) for one minute.

The recommended test voltage level is [(2 °- VLL + 1000) °- 1.7] kV DC for new windings (ANSI Std C50.10). The recommended test voltage level for field testing and maintenance purposes is 125 to 150% of (VLL °- 1.7) kV dc (ANSI Std C50.10). The value actually chosen for the test voltage is dependent on the age of the machine insulation, knowledge of its general condition, and the specific situation calling for a test.

11.5.8 AC HI-POT

The AC hi-pot test is also used to ascertain if the winding is capable of sustaining the required rated voltage levels (with-

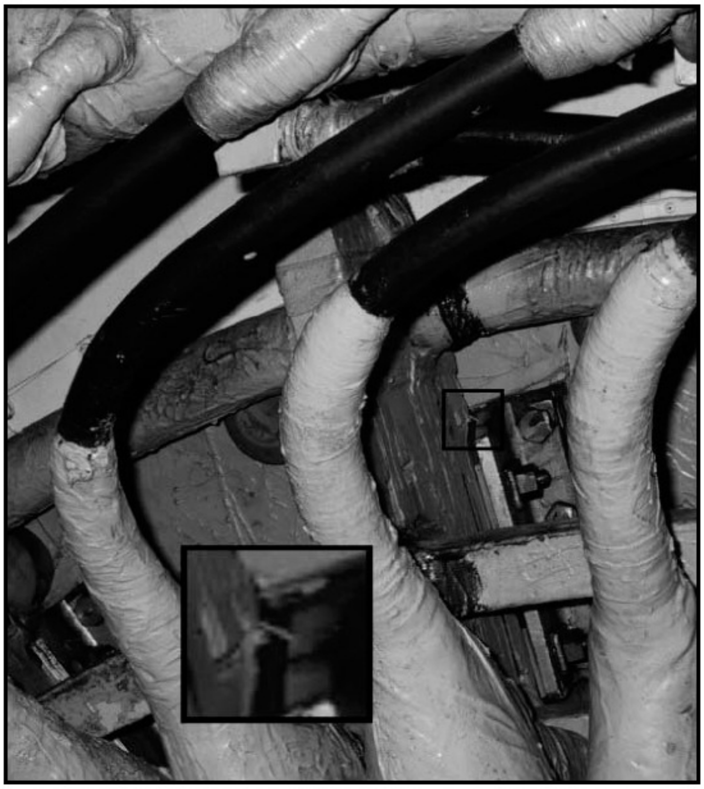


Fig. 11.27 Arcing occurring between a phase connector and ground during an AC hi-pot test.

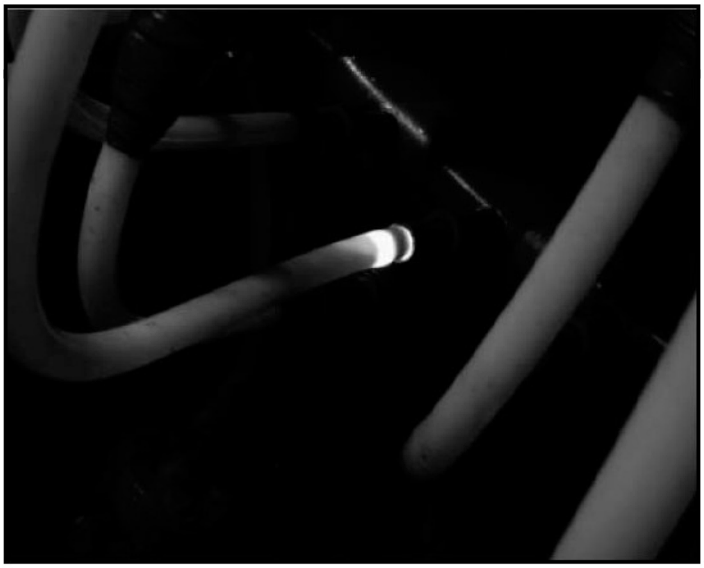


Fig. 11.28 Glowing hoses during a "wet" AC hi-pot test where contamination of the hoses is present.

out a breakdown of the insulation), with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying high voltage to the winding (the three phases together, or one at a time, with the other two grounded) for one minute.

The recommended test voltage level is (2 °- VLL + 1000) kV AC for new windings (ANSI Std C50.10). The recommended test voltage level for field-testing and maintenance purposes is 125 to 150% of VLL kV ac (ANSI Std C50.10). The value actually chosen for the test voltage is dependent on the age of the machine insulation, knowledge of its general condition, and the specific reasons for the calling for a test.

The AC testing is generally done at power frequency of 60 Hz but may also be carried out at a low frequency of 0.1 Hz, which is the accepted industry standard.

Generally, the AC hi-pot is a "pass" or "fail" type of test. However, this is not always the case. There are often times when arcing can be heard and even seen (Fig. 11.27), and the test can be stopped until the problem area is repaired. Then retesting may be carried out to prove the repairs.

Also, testing is usually done on water-cooled windings with the system drained and vacuum dried before voltage application. However, there are instances where good DC measurements have been recorded on two phases while one appears grounded, and the winding is technically "wet". In such an instance, AC testing has been done as a next step, but this is a rare occasion. It is not recommended to proceed with this type of testing unless an expert is present who knows how to handle this type of situation. One reason to do a "wet" AC test is when no failure point can be found, and yet the winding will not hold DC voltage and internal contamination of the stator winding hoses is suspected. Under dry conditions, the winding will pass high-voltage testing, and under wet conditions, the contamination will be conducting. Depending on the type of contamination and its conductivity, the hoses may glow under high voltage AC (Fig. 11.28).

11.5.9 PARTIAL DISCHARGE (PD) OFF-LINE TESTING

In principle, PD measurements are based on direct measurement of the pulses of high-frequency current discharges created during the occurrence of partial discharges. Some off-line methods are based in a capacitive link between the whole of the winding and the measurement equipment. These setups allow the measurement of PD activity in whole windings, or one phase at a time.

To measure the PD activity in smaller sections of the winding, methods based on an electromagnetic probe or pickup (which is mounted on a hand-held electrically insulated stick) has been developed. One such probe is known as the TVA probe and is used to traverse the entire length of a slot in the stator bore to search for localized sources of PD. Therefore each slot is probed over its full length.

The partial discharge tests are carried out from voltages below the inception voltage up to rated voltage.

On-line partial discharge analysis can be performed by modern instrumentation and methods described in the following sections.

PD Monitoring by Capacitive Coupling. Partial discharge monitoring by capacitive coupling is generally an on-line test nowadays, but off-line measurements are also done on a regular basis. The test setup for off-line capacitive coupling is generally as shown in Figure 11.29.

During operation of a generator, the voltage on the stator winding is graded according to the line to neutral connection. Thus, when an on-line test is performed, the bars near the neutral end of the machine are not subjected to high voltage, which represents the actual operating condition. In the off-line test, all stator bars are energized to the level of the test voltage applied, and therefore all may show PD activity. However, in the off-line test, the effects of vibration and bar forces are not in play. These issues are important to be taken into consideration when analyzing the test results, and their implication on the condition of the unit.

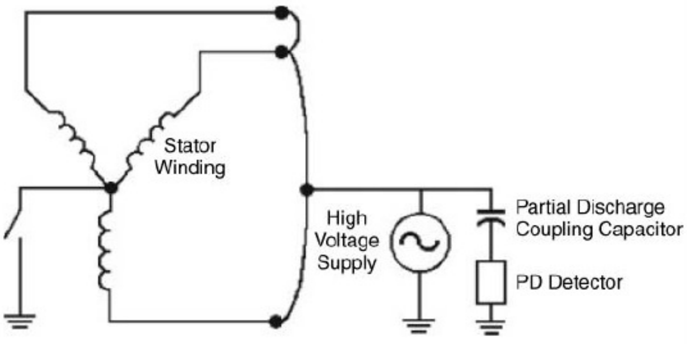


Fig. 11.29 PD testing by capacitive coupling, off line. (Courtesy of EPRI).

PD Monitoring by Stator Slot Coupler

The stator slot coupler (SSC) is basically a tuned antenna with two ports. The antenna is approximately 18 inches (46 cm) long and is embedded in an epoxy/glass laminate with no conducting surfaces exposed. SSCs are installed under the stator wedges at the line ends of the stator winding, such that the highest voltage bars are monitored for best PD detection. Since the SSC is also installed lengthwise in the slot at the core end, its two port characteristic gives it inherent directional capability.

The problem of noise is virtually eliminated in the SSC. Although the SSC has a very wide frequency response characteristic that allows it to see almost any signal present in the slot where it is installed, it also has the characteristic of showing the true pulse shape of these signals. This gives it a distinct advantage over other methods, which cannot capture the actual nature of the PD pulses. Since PD pulses occur in the 1 to 5 nanoseconds range and are very distinguishable with the SSC, the level of PD activity can be more closely defined.

In addition, dedicated monitoring devices have been devised to measure the PD activity detected in the SSC. The capability for PD detection using the SSC and its associated monitoring interface is enhanced to include measurement in terms of the positive and negative characteristic of the pulses, the number of the pulses, the magnitude of the pulses, the phase relation of the pulses and the direction of the pulses (i.e., now from the slot or from the endwinding or actually under the SSC itself at the end of the slot).

The other advantage of the SSC is that once it is installed, measurements may be taken at any time without the need for exposing live portions of the generator bus-work, for the purpose of making connections to the test equipment.

Corona Probing for PD. Partial discharge tests in general determine only the relative condition of the stator winding from the generator terminals. They do not locate specific sites of deterioration or damage in the winding. To do this, the winding must be locally scanned with special probes designed to detect localized sources of PD, while the winding is energized to the level of line-to-neutral voltage. There are a couple of variations of probe types, one based on radio-frequency noise and the other on acoustical noise. (SSCs do provide some information about the location of the PD activity. The more SSCs installed in a particular winding, the higher the accuracy in determining the location of the offending bar.)

The "TVA probe" gets its name from the Tennessee Valley Authority where it was first popularized. It is based on an earlier Westinghouse probe design that was sensitive to RF signals produced by PD in the winding. It functions by picking up the RF energy radiated from active PD sites in the winding.

The greater the PD, the greater the RF energy produced. The tip of the TVA probe employs a loop antenna similar to that used in an AM radio. The TVA antenna is tuned to about 5 MHz so that it is sensitive to near-field RF discharge.

The output of the antenna is directed by a co-axial cable to a tuned RF amplifier and a peak-reading ammeter that is sensitive to peak PD pulses. The closer the antenna is brought to an RF (or PD) source, the higher the output on the meter.

The "ultrasonic probe" functions based on acoustic noise produced by localized PD sites. The noise is similar to a crackling sound that one might hear when next to a high-voltage overhead transmission line on a wet day. This noise is loudest in the ultrasonic frequency range around 40 kHz. A high directional microphone, sensitive to the 40 kHz noise, is used to locate the site of the PD discharges.

Given that ultrasonic noise does not easily penetrate insulation, the ultrasonic probe test is primarily sensitive to surface PD, namely the sites of slot discharge and surface endwinding PD. See Figure 11.22

11.5.10 CAPACITANCE MEASUREMENTS

Capacitance measurements are also a method of measurement by which the quality of the insulation can be indicated. The measurements are, of course, done with AC voltage, and generally on a per phase basis.

Each phase of the stator winding is energized to line-to-neutral voltage, while the other two phases are grounded. The power factor of the winding is measured with a capacitance bridge to determine the value of the per-phase winding capacitance.

Comparison of the measured capacitance to the factory measured values, and then successive capacitance readings, can aid in showing deterioration of the ground-wall insulation over time.

11.5.11 DISSIPATION/POWER FACTOR TESTING

The dissipation factor (or tan ¥) is an AC test used to measure the bulk quality of the ground-wall insulation, by measuring the dielectric loss (primarily due to partial discharges) per unit of volume of the insulation. Note:

$$\text{(Dissipation factor) DF} = \tan\delta$$

$$\text{(Insulation power factor) IPF} = \frac{\text{DF}}{\sqrt{1 + (\text{DF})^2}} = \sin\delta$$

Results are generally dependent on the type of the dielectric material in the insulation system. An increase in DF over the life of the winding can be attributed to an increase in internal voids, de-laminations, and/or increased slot-coil contact resistance (i.e. deterioration of the semi-conducting paint in the slot).

The readings are a dimensionless quantity expressed as a percentage. The absolute values obtained are, again, a function of the type of insulation system being measured and are also directly affected by the temperature of the winding.

Therefore it is important that insulation power factor readings be taken at similar temperatures. The results are even

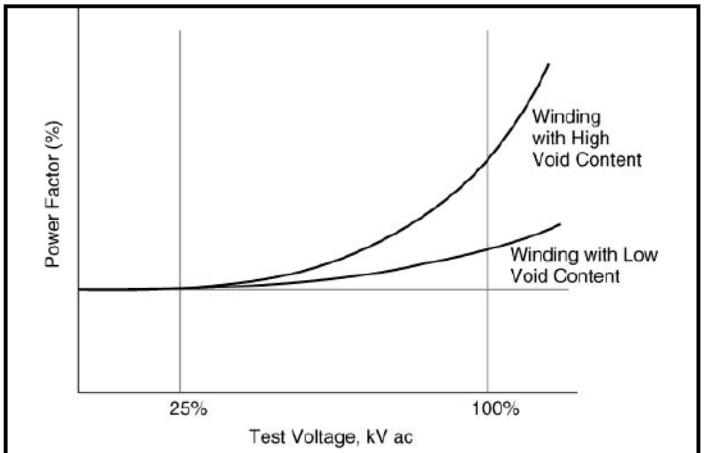


Fig. 11.30 Dissipation factor tip-up test profile comparison for good and poor results.

more useful, however, in relative terms by comparison of present readings to past readings. Successive measurements provide a scale of the deterioration rate of the insulation system over time.

Therefore, when using dissipation factor as a function of time, it is important to maintain constant conditions during testing. The DF readings are directly affected by the temperature of the winding and are also a function of the applied voltage.

Therefore comparisons with previous readings should be made on tests done at similar temperatures and the same voltage levels.

Since dissipation factor readings are somewhat void dependent, the dissipation/insulation power factor ratio will increase with an increase in the amount of voids present in the insulation. This phenomenon is the base of the DF/IPF tip-up test.

11.5.12 DISSIPATION/POWER FACTOR TIP-UP TEST

The dissipation factor tip-up or î tan ¥ test looks at the void content in the insulation.

That is to say, the dissipation factor will increase with an increase in the amount of voids or de-lamination present in the insulation. In addition it provides information on other ionizing losses in the form of partial and slot discharges.

The test is done by taking DF (or insulation power factor) measurements at different voltages. A set of readings is therefore obtained, which forms an ascending curve. A fast change of insulation power factor with increasing voltage tends to indicate a coil with many voids. The test is based on the fact that ionization, both internal and external to the insulation is voltage dependent.

The test is done generally at 25 and 100% of the rated phase to neutral voltage. The tip-up value is the DF measurement at the higher voltage, minus the DF measurement at the lower voltage (IEEE Std 286). Good readings for an epoxy/mica system, indicating minimal void content in the insulation, are typically less than 1%. Good readings for an asphalt system are generally in the 3% range (Fig. 11.30).

This test will give a good evaluation of the winding as a group. However, any bad coil that deviates greatly from the rest will not be discerned by this test. To ferret out individual bars that exhibit higher discharges, a partial discharge test is done with the addition of manual probing for the location of the discharges if high levels are found to exist.

11.6 ROTOR MECHANICAL TESTING

11.6.1 ROTOR VIBRATION

Vibration measurement is one the most important on-line measurements taken on the machine. Each manufacturer gives its own recommendations for alarm and trip.

The information in the following table is from an O&M engineering specification:

MACHINE SPEED	MAXIMUM AMPLITUDE
0-999 rpm	3 mils
1000-1499 rpm	2.5 mils
1500-2999 rpm	2 mils
3000 rpm & above	1 mil

Vibration is monitored continuously, and vibration charts are normally available at the control room. Vibration is monitored in all turbine and generator bearings.

Although vibration monitoring is generally considered an on-line monitoring function, there are many occasions where it is necessary to carry out additional and specific vibration testing. This would be to look for such problems as component rubs or rotor winding shorted turns to determine the correct course of action.

This type of detailed vibration testing is very specialized and requires additional equipment to be connected to the vibration probes installed on the generator.

The type of additional testing inferred would be to allow characterization of the vibration measurements into both magnitude and phase relation, and to allow frequency spectrum analysis during cold and hot run up to speed and run downs from speed. In addition load changes and field current changes allow the differentiation between mechanically and thermally induced vibrations.

11.6.2 ROTOR NONDESTRUCTIVE EXAMINATION INSPECTION TECHNIQUES

Non destructive examination of generator rotors is usually done to look for cracks and inclusions in highly stressed dynamic components. There are generally two types of NDE testing:

- o Surface (visual, magnetic particle, liquid penetrant, andeddy current);
- o Volumetric (radiographic and ultrasonic).

There are generally six different test methods:

- o Visual (VI);
- o Radiographic (RT);
- o Magnetic particle (MPI);
- o Liquid penetrant (LPI);
- o Ultrasonic (UT);
- o Eddy current (ECT).

Visual Inspection. Good detailed visual inspection of generator components may require any or all of the following conditions and equipment:

- o Adequate lighting;
- o Magnifying glass;
- o Mirrors with rotating heads;
- o Digital camera;
- o Borescope (with video recorder);
- o Feeler gauges;
- o Pocket ruler;

- o Straight edge;
- o Magnet.

The effectiveness of visual inspection is surprisingly good if the inspector is knowledgeable and thorough. For example, surface flaws - cracks, porosity, surface finish, rusting, and corrosion - can usually be easily seen, and much can be deduced from this type of inspection. From the visual inspection, one can sometimes determine as much as needed to make the right decision on maintenance action.

The advantages of visual inspection are that it is low cost, simple, and quick.

It can be done during any type of generator work that is in progress, permitting correction of faults.

Visual inspection does, of course, have limitations. It is applicable to surface defects only and provides no permanent record, unless recorded by photographs or video.

RADIOGRAPHIC

Radiographic testing is usually done by commercial X-ray or gamma units made especially for welds, castings, and forgings. It requires film and processing of the film when completed. It is not generally done for generator components, but it can be used if there are major frame weld problems. It is based on the difference in density or discontinuities in the item being examined.

The major defects that radiography can detect are interior macroscopic flaws such as cracks, porosity, and inclusions. Poor welds can be easily seen by this method.

This technique has the advantage of being applicable to most materials and once carried out, the defect areas are recorded on film to provide a permanent record.

The difficulties with radiography are that it requires skill in getting a good angle of exposure, use of the equipment, and interpreting the indications found.

It is also somewhat hazardous to health as any radiographic method and requires safety precautions to be taken to protect the equipment operator and any personnel in the area of the testing.

MAGNETIC PARTICLE

Magnetic particle inspection for surface flaws requires no special equipment. But it does require high current application to align the magnetic powders that show any flaws that are observable. This is in the range of 200 to 20,000 amps. The magnetic powders are in dry or wet form and may be fluorescent for viewing under ultraviolet light. Pigments are often added to dry metallic powders to make them more visible (yellow, red black, or gray). In the wet method, iron particles are coated with fluorescent pigment in water or oil-based suspension. Antifreeze may be added to water-based solutions to impede particle mobility.

Magnetization is done by passing current through a multi-turned coil, looped through or around the part to be examined, with no electrical contact. The magnetization field is parallel to the axis of coil-longitudinal magnetization. The flux density is proportional to the current times the number of turns in the coil.

With more turns, less current is required. A flux density of 1 tesla is satisfactory for most generator applications. Defects that are perpendicular to the magnetic field produce the most pronounced indications. The magnetic particles become attracted to discontinuities due to the high flux concentrations at the affected areas.

For low-carbon steels (with little or no retentiveness), a continuous application of magnetic particles is done while the magnetizing current is on. The magnetizing current is usually DC, from rectified AC. It is more penetrating than AC, up to half an inch below the surface.

For high carbon steels, (with high retentiveness), magnetizing current is applied, and then the magnetic particles, after the current is switched off. The magnetizing current is generally AC stepped down from single phase AC voltage. It is effective to approximately one one-thousandth of an inch below the surface.

Magnetic particle inspection or “mag-particle,” as it is commonly referred to, is common for use in rotor component inspection of forgings, couplings, and steel wedges. It is excellent for detecting surface or near-surface defects such as cracks in ferromagnetic materials. It is simple to perform and cost effective.

It is somewhat limited in that it is applicable to ferromagnetic materials only, and does require some skill in interpretation of defect indications and recognition of irregular patterns.

LIQUID PENETRANT

Liquid-penetrating inspection is widely used for generators, specifically on most rotor components, since it can be applied to both ferrous and nonferrous materials. It is primarily used for retaining-ring inspection. It is considered to have greater sensitivity than magnetic particle inspection, and is also a very cost-effective method of NDE.

The equipment required generally consists of the following:

- o Dye penetrating fluid, fluorescent or otherwise;
- o Developer;
- o Developer application equipment;
- o Ultraviolet light source, if the fluorescent method is used.

Dye-penetrating examination is able to detect surface cracks and pitting or any discontinuity open to the surface and not readily visible to the eye.

The technique requires a clean surface and so preparation of the surface by cleaning and polishing is first required. Then the liquid penetrant is applied and allowed time to weep into discontinuities by capillary action. Once penetration is complete, the excess penetrant is removed by wiping but not completely cleaned away. Next developer is applied, which absorbs the penetrant and acts as a type of blotter. Defects are then easily seen by eye.

The limitations of LPI are that it only detects surface defects and it is also temperature sensitive. It should only be used in the range of 60 to 90°F. This is due to viscosity issues with the penetrant as temperature varies outside the above-mentioned range.

Figures 11.31 to 11.33 show some of the uses on generators for defect detection.

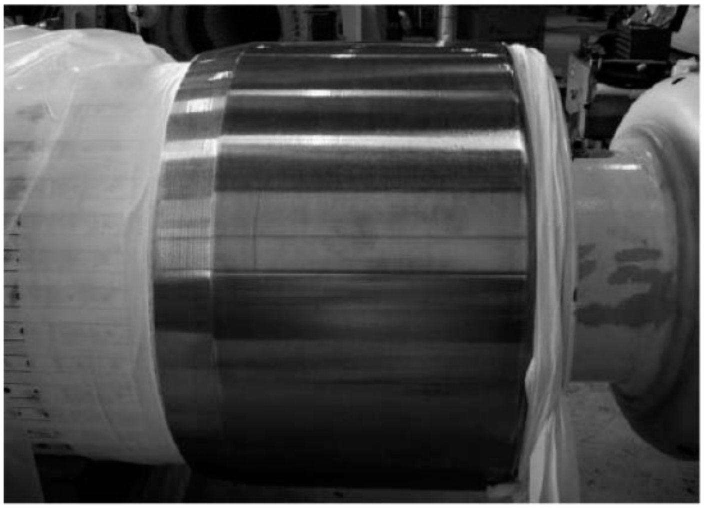


Fig. 11.31 18Mn-4Cr retaining ring-Fluorescent dye partially applied.

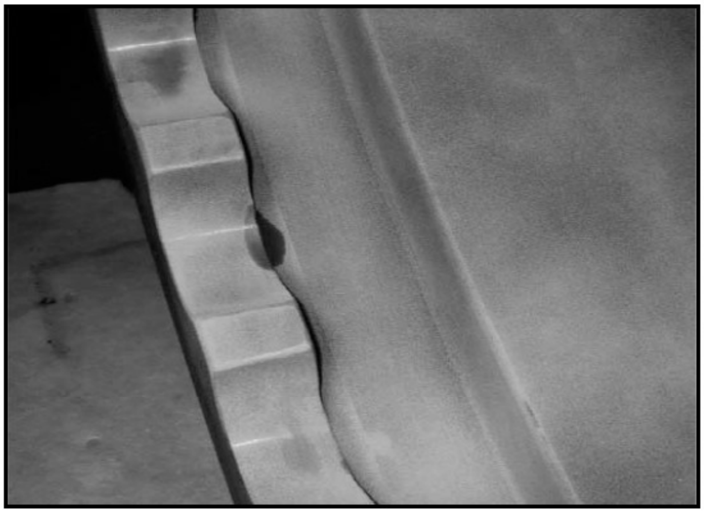


Fig. 11.32 18Mn-4Cr retaining ring-Developer applied and indication shown in the darkened spot at the castellated fitting.

Ultrasonic examination is probably the second most widely used NDE method on generator components. It is highly specialized and requires special commercial ultrasonic equipment, either of the pulse-echo or transmission type (Fig. 11.34).

UT is able to detect surface and subsurface flaws, including those too small to be detected by other methods. The size range in subsurface flaws is generally about 2 to 3 mm. Ultrasonic NDE is used for rotor forging bores, retaining rings, and specialized subsurface defects that can occur in high-stress areas or the rotor.

It is a very sensitive technique and can look at areas that are difficult access by other NDE methods. It does have the disadvantage that it is difficult to obtain good interpretable signals in areas where the specimen geometry is complex, such as the portion of a retaining ring where castellated fitting of the shrink fit area is employed. It also requires an operator with a high degree of training and skill to carry out the testing and interpret the results.

The two basic methods are described below:

PULSE-ECHO METHOD

The pulse-echo method is the most widely used method.

The ultrasonic pulse echo instrument generates high-voltage electrical pulses of short, evenly timed, duration. These pulses are applied to the transducer, which converts them into mechanical vibrations that are applied to the material being inspected. The sound reflected back to the transducer is converted back to electrical pulses, which are amplified and displayed on the cathode ray tube (CRT) as vertical pulses. The same transducer is used to transmit and to receive.

Through-Transmission Method

In the through transmission method, two transducers are required, one for sending and the other for receiving. Either short pulses or continuous waves are transmitted into the material. The quality of the material being tested is measured in terms of energy lost by a sound beam as it travels through the material.

To determine the location of discontinuities within a test

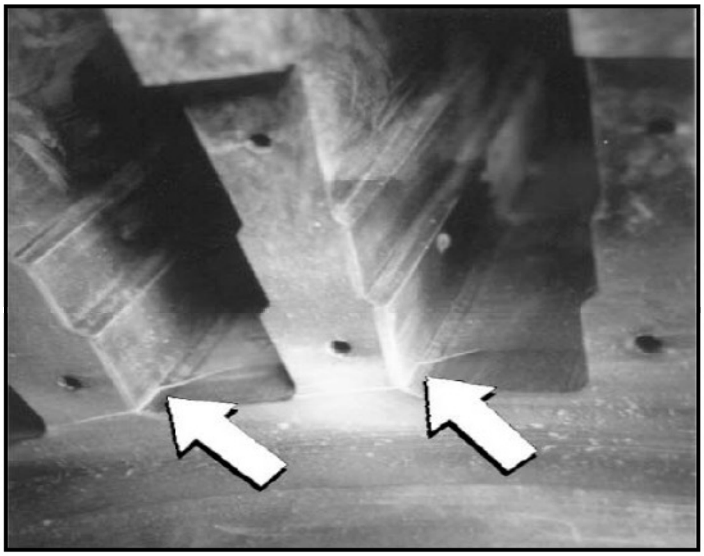


Fig. 11.33 Rotor forging tooth root cracks seen by fluorescent dye with developer applied.

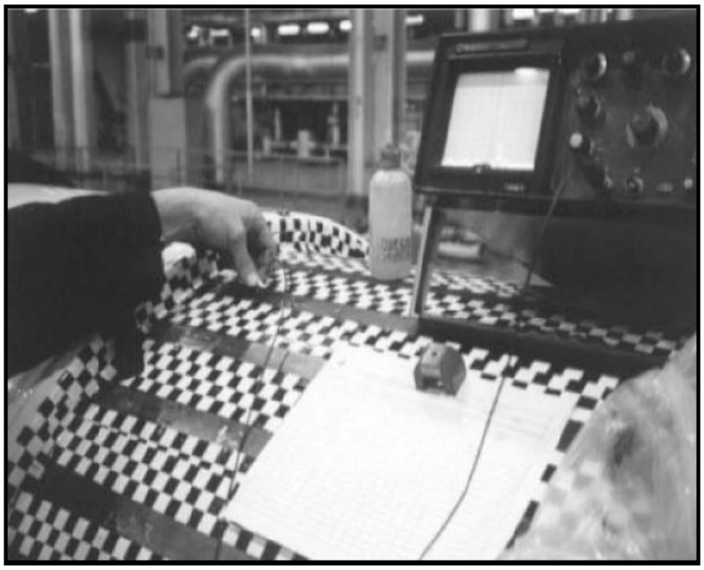


Fig. 11.34 Rotor forging tooth root cracks NDE by ultrasonic measurement with a 45-degree angle probe.

specimen, the visual display unit (VDU) horizontal display is divided into convenient increments such as centimeters or inches. At a given sensitivity (gain) setting, the amplitude is determined by the strength of the signal generated by the reflected sound wave.

The VDU thus displays two types of information: the distance (time) of the discontinuity from the transducer and the relative magnitude of the reflected energy.

There are generally two types of wave applications to the test specimen: longitudinal (compression) and shear (transverse) waves. Longitudinal waves have back and forth particle vibrations in the direction of the wave propagation. Shear waves have particle vibrations perpendicular to the direction of wave motion.

Shear waves will not travel through liquids or gasses. In some materials the velocity of a shear wave is about half that of longitudinal waves. Therefore the wavelength is shorter (by about half), permitting smaller discontinuities to be located.

Grain structure has a great influence on the acoustical properties of a material.

A steel forging generally has a fine-grain structure, and has a low-damping effect on the sound beam. A casting, however, generally has a coarser grain structure, which is more difficult to get sound through.

When a discontinuity is not normal (at 90 degrees) to the incident wave, the reflected wave will be at an angle. The result is a reduction in the amplitude of the discontinuity indication displayed on the CRT.

Transducers come in many shapes, sizes and physical characteristics. Some common types include paintbrush, dual element, single element, angle beam, focused, mosaic, contact, and immersion. Single-element transducers may be transmitters only, receivers only, or both. Double-element transducers may be single transducers mounted either side by side or stacked. In a double-element transducer, one is a transmitter and the other is a receiver. Double-element transducers have better near-surface resolution because the receiver can receive discontinuity signals before the transmitter completes its transmission.

EDDY CURRENT

Eddy-current examination requires very special commercial type equipment, consisting of the following components:

o Vector voltmeter;
o Differential bridge;
o Sensor coils;
o Frequency generator;
o Phase sensitive detector;
o Impedance plane display instrument.

Eddy current is not widely used for generator applications, but it has been useful on occasion where tight cracks in retaining rings cannot be seen by LPI, MPI, or UT. It is able to penetrate layers of good material to detect hidden flaws in metals such as inclusions and tight cracks. Examples of the types of defects that can be seen by eddy current are surface and near-surface defects, de-lamination of multi-layered components, and inclusions.

The basic principle is that of an alternating current flowing through a coil, producing an alternating magnetic field in the specimen being tested. When the coil is then placed near a test specimen that is conductive, the magnetic field causes eddy currents to flow. This flow of eddy currents depends on the physical and electrical characteristics of the test specimen. The eddy currents will avoid cracks and seek higher conducting regions in the specimen. As the eddy currents flow in the test specimen, they generate their own magnetic field. This field interacts with the magnetic field produced by the coil and changes the coil's impedance. Specialized instruments then measure and display these changes in the impedance, allowing the test technician to interpret information about the test specimen, specifically the presence and size of flaws in it.

There are numerous types of eddy current probes used, and the type of probe chosen depends on the material being tested and the application. The types of probes are absolute, differential, reflection, unshielded, and shielded. The main advantages to this method in general are low cost, ease and speed of use, high sensitivity to microscopic defects, and its automation.

11.6.3 SOME ADDITIONAL ROTOR NDE SPECIFICS

NDE tests are generally done on the following generator rotor components:

o Forging;
o Retaining-rings;
o Fans.

Typical NDE tests include magnetic particle, liquid penetrant, ultrasonic (and bore-sonic), and sometimes eddy current. An additional test hardness test is sometimes performed.

ROTOR FORGINGS

NDE is most often done during rewinding of the rotor, when re-validation of the forging is required. This may include the following inspections:

o Magnetic particle inspection (MPI) of the rotor fillet radii inboard of the journals, shaft radius at the slot exit interface, fan seating and keyways, pole face crosscuts, pole and winding slots, and so on;

o Liquid penetrant inspection (LPI) of the exciter end lead slot radii, inboard and outboard radial pinholes, and coupling bolt holes;

o Ultrasonic examination of the rotor bore (boresonic).

In addition, the rotor forging generally undergoes full-dimensional checks and run-out or truth checks.

FANS

Rotor fans are highly stressed components of the rotor. Fan blades and vanes are generally tested by LPI and UT.

RETAINING-RINGS

Retaining-rings are by far the component subjected to the highest scrutiny during major overhauls. One of the most comprehensive studies on this topic is given in the EPRI Special Report EL/EM-5117-SR, “Guidelines for Evaluation of Generator Retaining-Rings,” April 1987 [18].

Generally, generator rotors employ three different types of retaining-ring material.

These are Ni-Cr-Mo-Va magnetic steel (ferritic), 18Mn-5Cr nonmagnetic steel, and 18Mn-18Cr nonmagnetic steel.

One of the major station concerns is the ability to perform NDE on large generator rotor retaining-rings without removing the rotors from the generator, let alone the retaining-rings from the rotors. This is driven by the high cost of rotor removal and subsequent removal of the retaining-rings from the rotors, and the time consumption involved. In addition, removing retaining-rings is not desirable because of the risk of damaging the rings, the rotor forging, and/or end-windings in the process.

Retaining-rings constructed from magnetic material are generally sound in terms of strength and resistance to corrosion, and so on. However, they are undesirable with regard to their electromagnetic characteristics and resulting effect on the overall machine losses.

Generator rotor retaining-rings made from 18Mn-5Cr austenitic, nonmagnetic steel are, on the other hand, highly susceptible to the mechanism of stress corrosion cracking when exposed to a moisture laden environment during operation or at a standstill. This has become an industrywide problem without regard to a specific manufacturer.

Several ring failures have occurred in the industry, resulting in considerable damage to the overall generators and their support structures. These incidents were attributed to stress corrosion cracking caused by exposure to moisture.

These rings had apparently not been adequately protected from the environment.

Once a crack has been initiated, the propagation rate of the crack will depend on, the ring design (geometry, stress levels, etc.), environment and the operating conditions to which it is subjected. It is extremely difficult to predict when small cracks will reach the critical crack size to which failure is imminent. An attempt has been made and is published. Inspection is the only means available to assess retaining-ring integrity, and provide an opportunity to correct problems encountered.

With the advent of a new retaining-ring material known as 18-18 (18Mn-18Cr), which is highly resistant to the stress corrosion cracking mechanism, all manufacturers are advocating that the 18Mn-5Cr retaining rings be replaced with new 18-18 rings because of their superior properties. 18Mn-18Cr steel is claimed to be very resistant to corrosion and stress corrosion cracking in the operating environments of large generators. As a result, fewer inspections will be needed for the retaining-rings.

Testing Frequency. Depending on availability, it is desirable to conduct retaining-ring inspections during a period of one to two years following the in-service date, and again six to eight years after that. Subsequent inspections are prescribed based on a combination of information gained during previous inspections, and adverse operating conditions since the last inspection.

Adverse operating conditions would include water leakage into the generator, high or sustained dewpoint excursions, local system faults, synchronizing errors, high rotor temperature excursions, continuously changing load requirements or two shifting, overspeeds, rotor at standstill in uncontrolled environmental conditions, and so on.

Inspection Procedure. The recommended process for an acceptable assessment of retaining-ring integrity requires removal of both rings from the rotor body completely. A thorough cleaning of all ring surfaces prior to inspection follows this. The cleaning is achieved by hand polishing of shrink-fit areas, and by using electrically nonconductive abrasives on all surfaces to achieve bare metal conditions.

The inspection is carried out during a detailed dye penetrant process, using a highly sensitive fluorescent liquid penetrant to expose suspect areas containing cracks, pits, or defects.

Local grinding and/or polishing will normally remove any flaws, but there are limitations on the amount of corrective action allowed. It is essential that the limits not be exceeded during the corrective action as the suspect areas are removed.

Removal of material from the shrink-fit area is limited to the amount at which 15% overspeed capability is maintained. The design overspeed capability is 20% above operating. Overspeed trips are set at 10%, thus allowing a minimum 5% margin for the material to be removed. The determination of the depth of the skim to be taken off the shrink-fit, when required, should be referred back to the OEM.

ACCEPTANCE CRITERIA

Acceptance criteria are normally determined by, and are the responsibility of, the manufacturer/supplier of the item being assessed.

However, acceptance criteria is usually based on detection of defects and not crack/pit/defect sizing. It is much easier to establish an acceptable situation by first establishing “not-acceptable” criteria.

A reasonable not-acceptable criteria adopted by some OEMs and users is as follows:

1. No linear defects > 1 mm in length.
2. No linear array of 3 or more point defects with < 3 mm between points.
3. No random groups of 3 or more point defects within a circle of < 5 mm diameter.
4. No random groups acceptable to criteria 3 but < 5 mm from a similar group.

Note: A point defect is a surface defect < 0.5 mm in diameter.

IN-SITU TESTING

At the present time, ultrasonic examination of retaining-rings assembled on a rotor body is being debated by users and testers in the industry.

There are some who are staunch proponents of the in-situ technique, while others insist it is not sensitive enough.

At last report to the authors, the smallest cracks that can be detected are in the order of 2 to 3 mm in the shrink area and only as small as 1 mm in the smooth bore areas. On rings with castellated fittings, it may not be possible to resolve indications identified due to the complex geometry involved.

It should also be understood that these crack sizes quoted above are large in terms of significance for retaining-rings. Even pitting marks will propagate into cracks when the internal generator hydrogen conditions are not good. The critical crack size is different for each ring design and must be evaluated independently.

The bottom line is that even the smallest cracks cannot be tolerated, especially in the shrink area. It is the modest opinion of the authors that the only way to know for sure if the ring is free of defects is to remove it for detailed NDE surface type inspection methods and ultrasonic or eddy current for detection of inclusions.

Finally, there are some in the industry who consider it desirable to install the new 18Mn-18Cr retaining-rings so that inspection is unnecessary. Figure 11.35 shows an in-situ testing device in operation.

11.6.4 AIR PRESSURE TEST OF ROTOR BORE

The vast majority of large generator rotors in existence have hollow bores, which extend the full length of the rotor forging. These boreholes are generally in the range of 3 to 5 inches (≈ 7.5-13 cm) in diameter, and when the contents of the bore are removed, one can see from one end right through to the other.

Boreholes were used mostly in past due to impurities and porosity in the forgings, which tended to concentrate in the center. They serve two purposes: the first is to remove the material defects, and the second is to provide an access for performing boresonic (ultrasonic) inspection of the rotor bore. In modern forgings the material manufacturing processes are so improved that a full rotor length borehole is not generally required. Only a short borehole at the exciter end of the rotor is provided to accommodate the up-shaft lead, which connects the rotor winding to the slip-rings via the radial terminal studs.

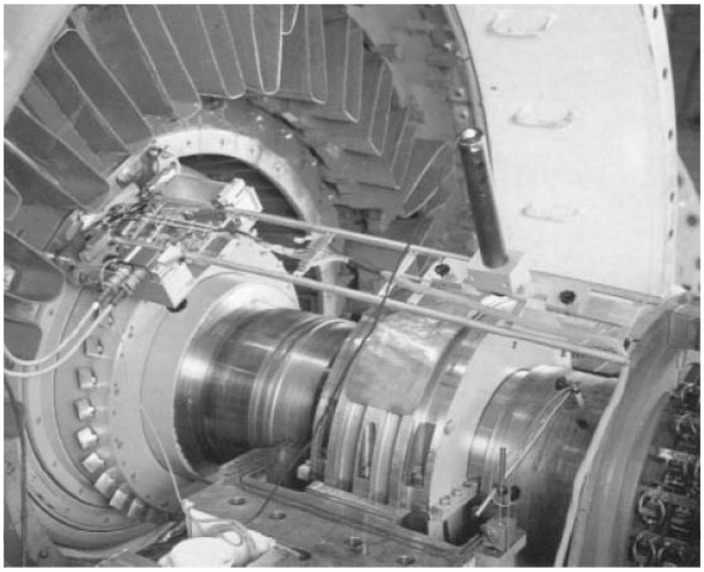


Fig. 11.35 In-situ robotic rotor retaining-ring ultrasonic testing. (Courtesy of Alstom).

In hydrogen cooled machines rotor seals are installed in the shaft, sealing the hole in the shaft where the up-shaft lead or bore copper is installed. This is between the sliprings and the field winding. The seals are generally made of rubbery material, which under pressure (sometimes from a nut) expands filling the area between the bolt connecting the bus/conductor in the hollow of the shaft to the slip-rings. On the excitation end, some rotors have only one set of seals close to the collectors, while other rotors have a second set of seals, where the leads exit shaft, under the retaining rings. On rotors with a full-length borehole the turbine end of the rotor is also sealed by a faceplate arrangement on the coupling face.

The integrity of the rotor seals is normally checked during major overhauls.

Depending on the design of the rotor, some can be pressure-tested by a nipple permanently installed on the shaft, or by placing a can over the shaft extension and collector assembly, tightly sealed against the rotor forging, and pressurizing the can.

11.7 ROTOR ELECTRICAL TESTING

11.7.1 WINDING RESISTANCE

The field-winding series-resistance is measured to determine the ohms resistance of the total copper winding in the rotor. Given the relatively low DC series resistance of windings of large machines, the measurement accuracy requires significance to a minimum of four decimal places.

The purpose of the test is to detect shorted turns, bad connections, wrong connections, and open circuits. The machine should be at room temperature when the test is performed. As with most other electrical test, the results should be compared with original factory data, if available.

11.7.2 INSULATION RESISTANCE (IR)

The purpose of the IR test is to measure the ohmic resistance between the total rotor winding insulation and ground (i.e., the rotor forging). This test is generally regarded as an initial test to look for gross problems with the insulation system and to ensure further high voltage electrical testing may (relatively) safely continue, in terms of danger of failing the insulation.

Normally, the measurements of IR will be in the megaohm range for good insulation, after the winding is subjected to a DC test voltage usually done anywhere from 500 to 1,000 V, for one minute. The minimum acceptable reading by IEEE Standard 43 is (Vf in kV + 1) M©. The test is carried out with a megger device. The DC test voltage level is usually specified based on the operating and field forcing voltage of the rotor, utility policy and previous experience, and knowledge of the present condition of the insulation in the rotor.

It is essential that the rotor winding be completely dried before any testing so that any poor readings will be due to a "real" problem and not residual moisture.

The readings are also sensitive to factors like humidity, surface contamination of the coils, and temperature. Readings should be corrected to a base temperature of 40°C (Fig. 11.24).

All of the above also applies to the rotor bore copper and collector rings.

11.7.3 POLARIZATION INDEX (PI)

Insulation resistance is time dependent as well as being a function of dryness for rotor insulation, just as in the stator. The amount of change in the IR measured during the first few minutes depends on the insulation condition, and the amount of contamination and moisture present. Therefore, when the insulation system is clean and dry, the IR value tends to increase as the dielectric material in the insulation absorbs the charge. When the insulation is dirty, wet, or a gross insulation problem is present, the charge does not hold. The IR value will not increase because of a constant leakage current at the problem area. Thus the ratio between the resistance reading at 10 minutes and the reading at 1 minute produces a number or "polarization index," which is essentially used to determine how clean and dry the winding is.

The recommended minimum PI values are as follows:

o Class B insulation: 2.0

o Class F insulation: 2.0

The same megger used for the IR readings should be used to determine the PI.

The PI readings should be done at the same voltage as the IR test and can be used as a go/no-go test before subjecting the rotor to subsequent high voltage tests, either AC or DC. The IR readings for the PI test should also be corrected to 40°C as in the IR test (Fig. 11.23). Performing the high-voltage tests on wet insulation can cause needless failure of the insulation.

11.7.4 DC HI-POT

The DC hi-pot test is used to ascertain if the winding is capable of sustaining the required rated voltage levels (without a breakdown of the insulation), with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying high voltage to the rotor winding for one minute.

The DC Hi-Pot testing on rotor windings is normally done between 1500 V up to approximately 10 times the rated field voltage.

11.7.5 AC Hi-Pot

The AC hi-pot test is also used to ascertain if the winding is capable of sustaining the required rated voltage levels (without a breakdown of the insulation) with a reasonable degree of assurance for capability to withstand overvoltages and transients, and maintain an acceptable insulation life. The test consists of applying AC high voltage to the rotor winding for one minute.

The AC hi-pot testing on rotor windings is also normally done at to 10 times the rated field voltage at line frequency of 60 Hz.

11.7.6 SHORTED TURNS DETECTION - GENERAL

Shorted turns in rotor windings are associated with turn-to-turn shorts on the copper winding, as opposed to turn to ground faults. Rotor winding shorted turns, or inter-turn shorts can occur from an electrical break down of the inter-turn insulation, mechanical damage to the inter-turn insulation allowing adjacent turn to turn contact, or contamination in the slot that allows leakage currents between turns.

When shorted turns occur, the total ampere-turns produced by the rotor are reduced, since the effective number of turns has been reduced by the number of turns shorted. The result is an increase in required field current input to the rotor to maintain the same load point, and an increase in rotor winding temperature.

At the location of the short, there is a high probability of localized heating of the copper winding and arcing damage to the insulation between the turns.

This type of damage can propagate and worsen the fault, such that more turns are affected or the ground-wall insulation becomes damaged, and a rotor winding ground occurs.

One of the most noticeable effects of shorted turns is increased rotor vibration due to thermal effects. When a short on one pole of the rotor occurs, a condition of unequal heating in the rotor winding will exist between poles. The unequal heating may cause bowing of the rotor, and hence vibration. The extent and location of the shorted turns and the heating produced will govern the magnitude of the vibrations produced.

A general relationship between the location of the shorted turn/turns and vibration is as follows:

o Lower vibration is generally experienced when the short is on the Q axis.

o Higher vibration is generally experienced when the short is nearer the pole or D axis.

Stated differently, the rotor is more prone to vibration due to shorted turns if the shorts are located in the “small coils” rather than in the “large coils”. The “small coils” being those located closer to the pole faces.

The reasoning for the above is the lack of symmetry with faults nearer the pole face. There is an inherent unbalance in the geometry and heating effect on the rotor forging.

Off-line methods for detecting shorted turns include winding impedance measurements as the rotor speed is varied from zero to rated speed, and RSO (recurrent surge oscillation) tests, based on the principle of time domain reflectometry.

In addition, a short of significant magnitude may be identified by producing an open circuit (OC) saturation curve, and comparing it to the design OC saturation curve. If the field current required to produce rated terminal voltage has increased from the original design curve, then a short is likely present. The number of shorted turns may be identified by the ratio of the new field current value over the design field current value.

All of these methods of identifying shorted turns are prone to error and only indicate that a short exists. They do little to help locate which slot the short is in and require special conditions for collecting the data or for testing. To better identify shorted turns, and to employ a method that works on line, the search coil method has been perfected. Each OEM has their own version of a search coil method, but all work essentially in the same manner.

11.7.7 Shorted Turns Detection by Recurrent Surge Oscillation (RSO)

In the RSO method, a low-voltage (a few volts) high-frequency (kHz range) surge wave is injected at each one of the collector rings. The two signals are then compared to determine if the same waveform is observed at each collector ring. If the waveform is identical, then no shorts are present. Variations in the two waveforms indicate shorts to be present. This method is based on the principle of time domain reflectometry.

This method has the advantage of allowing the rotor to be spun, while doing the measurements, to determine if the shorts are also speed sensitive. The advantage of this is that the mechanical loading effects can be taken into consideration. In the spinning RSO, there may be shorts that reveal themselves that are not seen when the rotor is at rest, since at rest there is no mechanical load on the winding turns other than their own weight.

Because the RSO also works on a time-of-flight principle, the location of the coil number where the shorts are, as well as which pole, becomes discernable by this method. Shorts nearer the slip-rings show up as blips in the RSO pulse nearer the left side of the traces. The magnitude of the blip increases for the number of turns shorted at the particular location (i.e., the particular coil) as more turns are shorted.

In the “at-rest” test, the RSO is connected directly to the winding via the collector rings. Thus only the winding impedance is seen by the high-frequency, low-voltage pulses sent by the RSO. In the “spinning” RSO test, to accommodate the moving rotor, the leads of the RSO must be connected to the brush-rigging, and the connection to the winding is then implemented via the brushes' collector rings. However, with this connection anything connected toward the excitation equipment is “seen” by the pulses (e.g., leads, contacts, field breaker, field resistor, and excitation equipment). The principle of operation of the RSO is comparing the pulses inserted in each polarity terminal of the winding, and their reflections. The test is extremely sensitive to any asymmetry on the path of the pulses. From a point of view of the wave impedance seen by the high-frequency pulses, the field winding is by nature very symmetrical, but the excitation system is anything but that. Therefore, in order to obtain any significant signature on the condition of the field-winding, the “noise” originating in the path toward the excitation must be reduced as much as possible. This is achieved by opening the excitation leads at a convenient location between the excitation system and the brush-rigging. After the leads are open, only cables of almost exactly equal length are left connected to the brush rigging. The effect introduced by these cables is generally negligible.

Figures 11.36 to 11.42 depict samples of RSO test-readings taken on a twopole turbogenerator rotor.

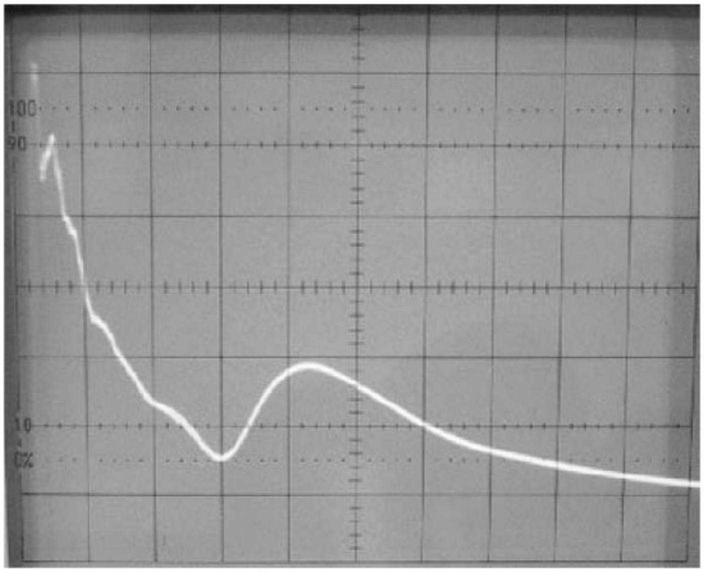


Fig. 11.36 No shorted turns - Dual traces superimposed.

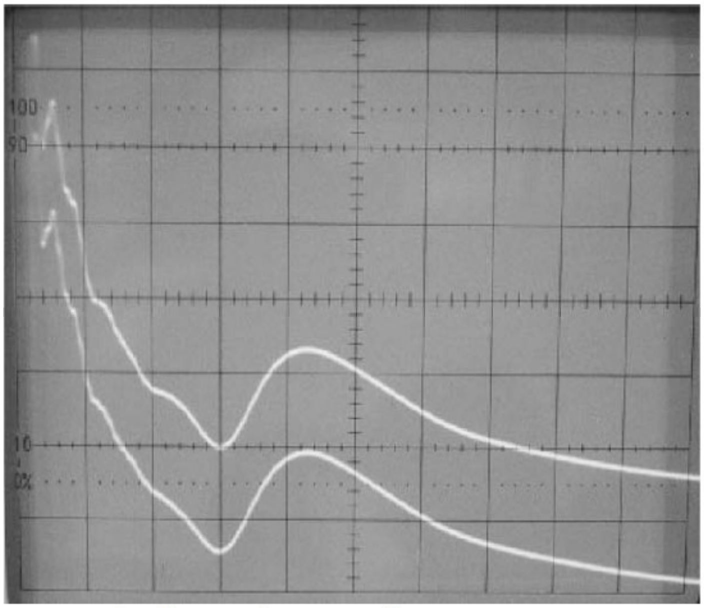


Fig. 11.37 No shorted turns - Dual traces separated.

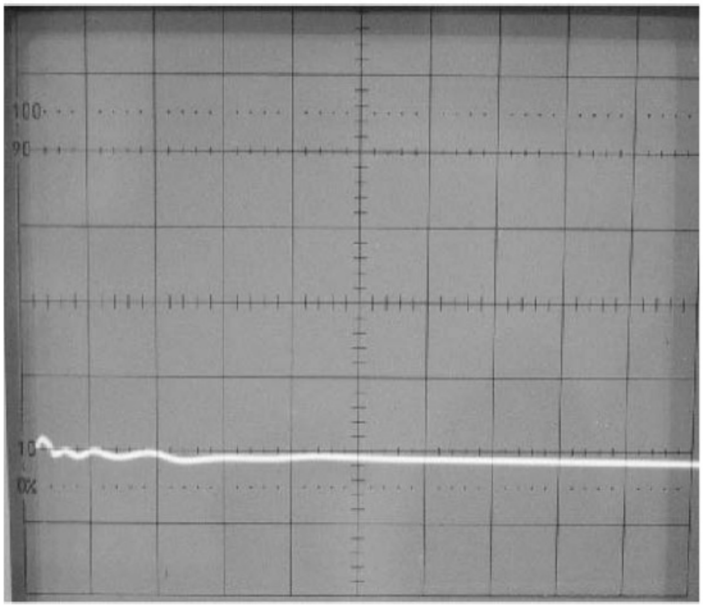


Fig. 11.38 No shorted turns - Difference trace.

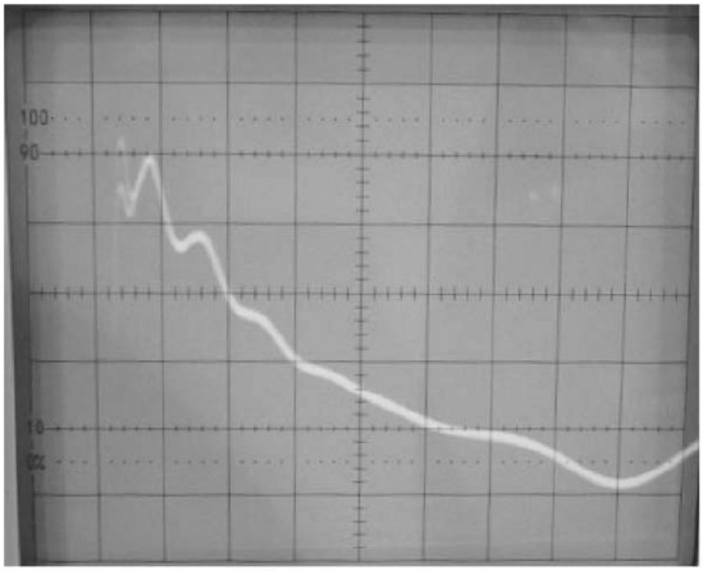


Fig. 11.39 One shorted turn, coil #1 - Dual traces superimposed.

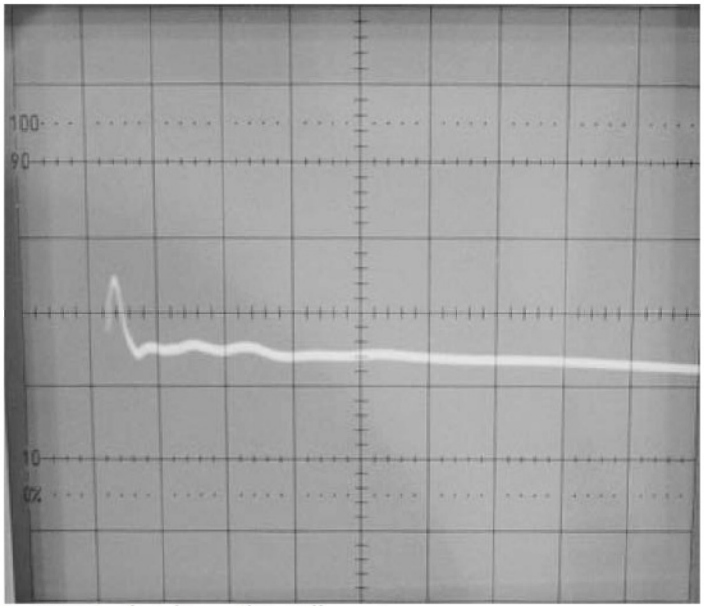


Fig. 11.40 One shorted turn, coil #1 - Difference trace.

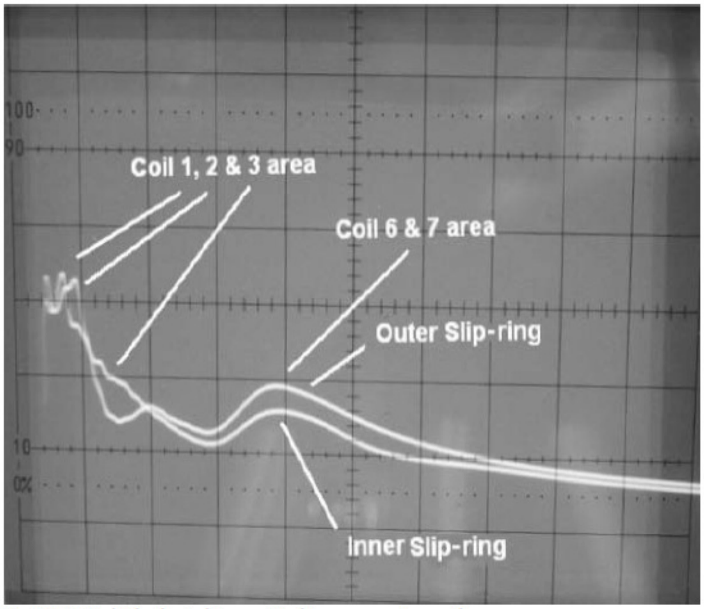
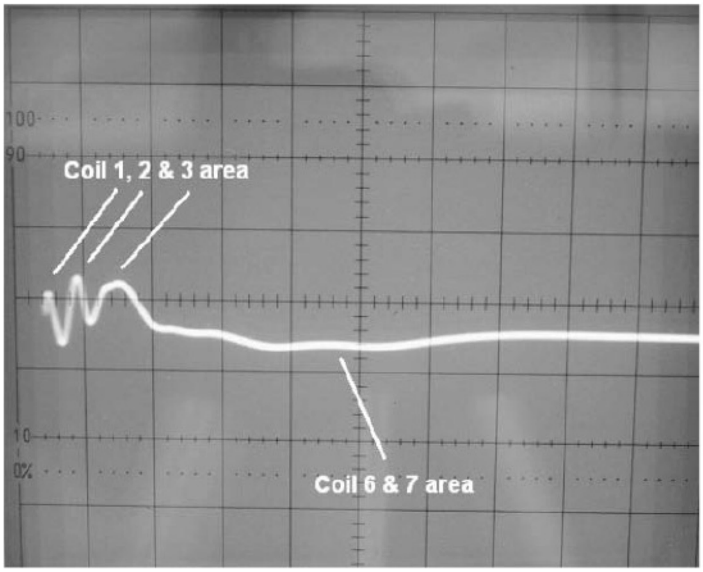


Fig. 11.41 Multiple shorted turns - Dual traces superimposed.



11.7.8 SHORTED TURNS DETECTION BY OPEN-CIRCUIT TEST

Producing an open-circuit saturation curve, and comparing it to the design open-circuit saturation curve may identify a shorted turn condition of significant magnitude.

If the field current required to produce rated terminal voltage has increased from the original design curve, then a short would be likely present (Fig. 11.43).

The number of shorted turns may be identified by the ratio of the new field current value over the design field current value. However, due to the many number of turns in a typical rotor winding, the changes in open-circuit voltage due to a single shorted turn in the field-winding may go unnoticed since the measurement is too small for a positive identification.

The open-circuit stator voltage versus field current characteristics can be measured in all synchronous machines. This curve, taken with the machine spinning at synchronous speed, is unique for each machine. In principle, the OC test allows detecting shorted turns in brushless machines, where RSO techniques are too difficult to perform, and always entails partial disconnection of the rotor leads.

11.7.9 SHORTED TURNS DETECTION BY WINDING IMPEDANCE

Impedance measurements while the machine is decelerating or accelerating can also be used to detect a speed-dependent shorted turn. Any sudden change in the readings may indicate a shorted turn being activated at that speed. A gradual change of impedance of more than 10% may also indicate a solid short (Fig. 11.44).

11.7.10 SHORTED TURNS DETECTION BY LOW-VOLTAGE DC OR VOLT DROP

This test is designed to determine the existence of shorted turns in the rotor winding. The test is entirely different when performed on salient pole rotors than in cylindrical (round) rotors.

In salient pole machines, a "pole drop" test is done. In this test, the resistance across each individual pole is measured by the V/I method, namely by applying a voltage of around 100 to 120 volts, 60 Hz, to the entire winding, and then measuring the voltage drop across each pole. A pole with lower voltage

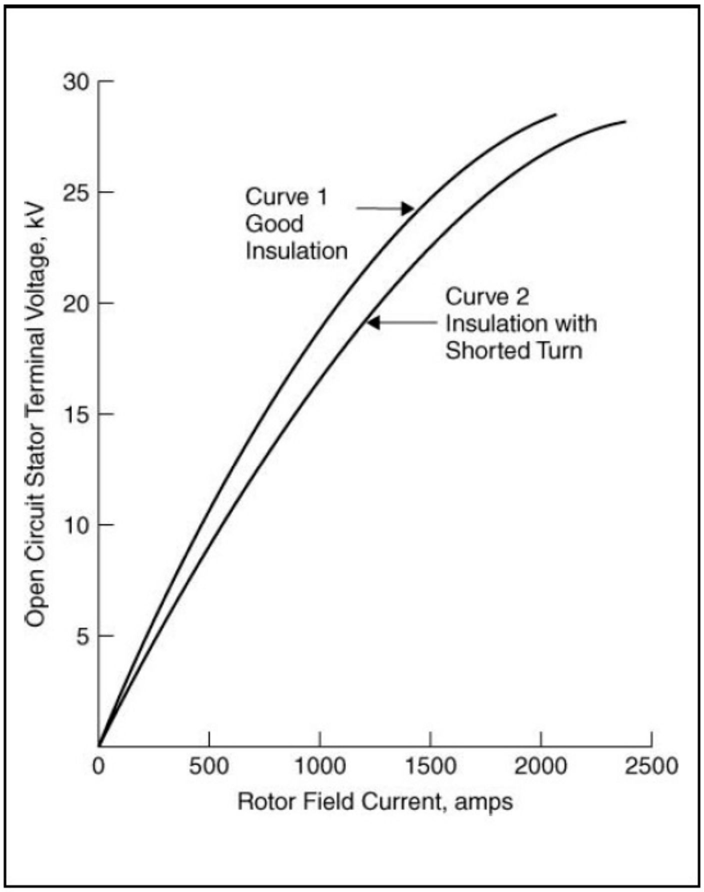


Fig. 11.43 Shorted turns detection by open-circuit saturation curve. (Courtesy of EPRI).

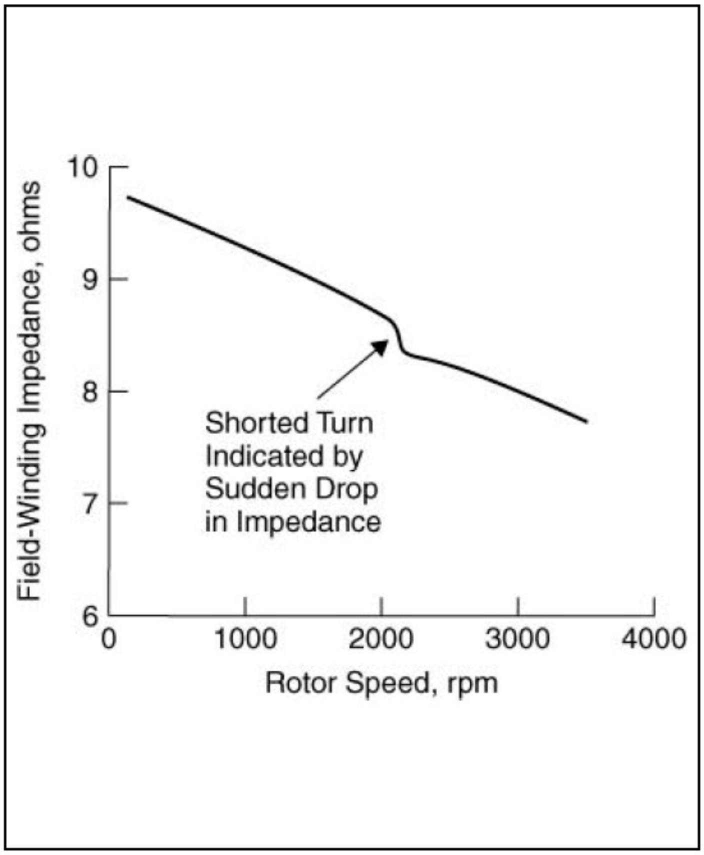


Fig. 11.44 Shorted turns detection by impedance testing. (Courtesy of EPRI).

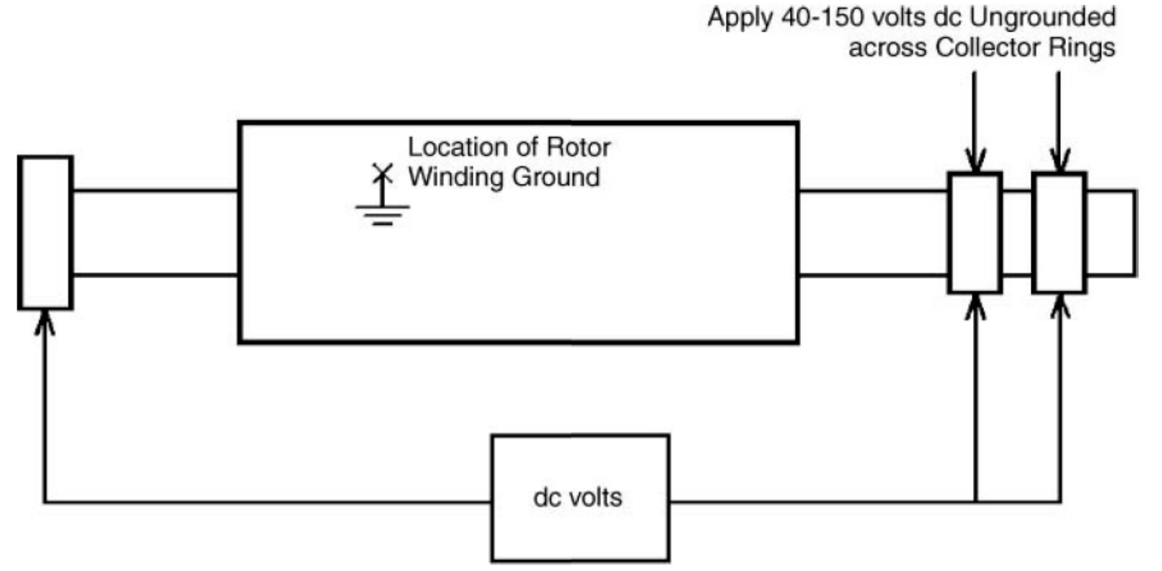

Apply 40-150 volts dc Ungrounded across Collector Rings
Location of Rotor Winding Ground
dc volts

Fig. 11.47 Rotor ground detection by split voltage test.

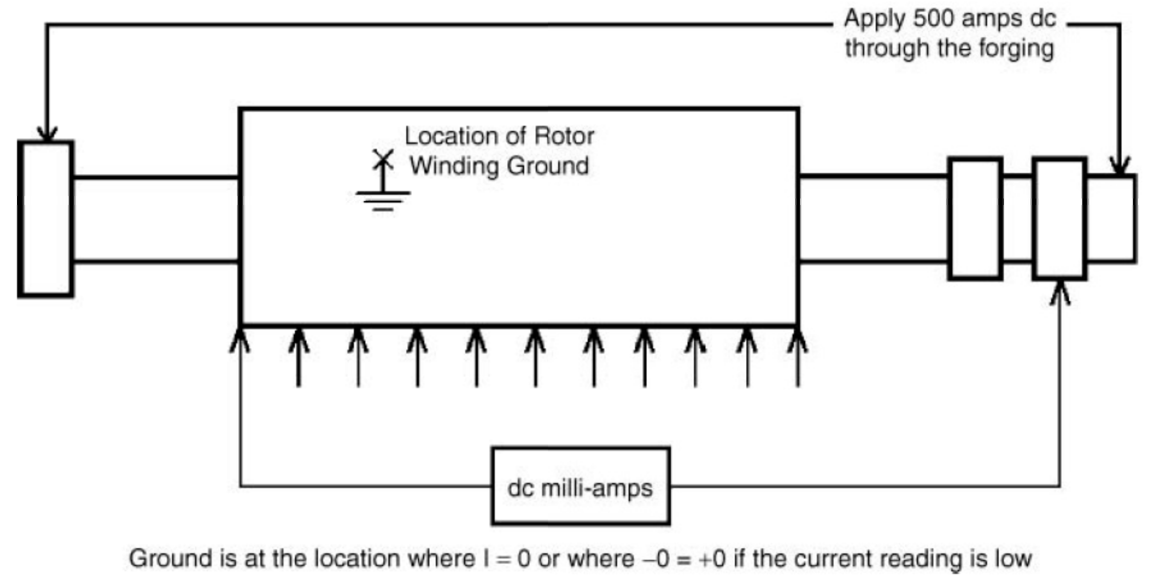

Apply 500 amps dc through the forging
Location of Rotor Winding Ground
dc milli-amps
Ground is at the location where I = 0 or where –0 = +0 if the current reading is low

Fig. 11.48 Rotor ground detection by current through forging test.

drop will indicate a shorted turn or a number of shorted turns.

In either salient pole or round rotor machines, the shorted turns are often speed dependent (i.e., they might disappear at standstill). To partially offset this phenomenon, it is recommended to repeat the pole drop test a few times with the rotor at several angles. The gravity forces exerted on the vertically located poles may activate some short circuits between turns, which might not show up when in, or close to, the horizontal position.

In round rotors, the individual windings are generally not accessible unless the retaining rings are removed. Therefore, detection of shorted turns in not always possible by this method.

11.7.11 SHORTED TURNS DETECTION BY LOW-VOLTAGE AC OR "C" CORE TEST

A C-shaped, wound core is required to carry out this test, together with a voltmeter, wattmeter, and single-phase power supply (Fig. 11.45). Shorted turns are detected by sharp changes in the direction of wattmeter readings (Fig. 11.46).

In rotors with damper windings, or with the wedges short-circuited at the ends to form a damper winding, these have to be disconnected at the ends. This operation requires removal of the retaining rings.

11.7.12 SHORTED TURNS DETECTION BY SHORTED TURNS DETECTOR (FLUX PROBE)

The flux probe is actually a search coil mounted on the stator core by various methods, but located strategically in the airgap. The search coil looks at the variation in magnetic field produced in the airgap by the rotor as it spins. The energized rotor winding and the slotted effect of the winding arc cause a sinusoidal signal to be produced in the winding face of the rotor. The pole face, on the other hand, has no winding and the signal is more flat since the variation in magnetic field is minimal.

The magnitude of the sinusoidal peaks in the winding face is dependent on the ampere-turns produced by the winding in the various slots. If there is a short in a slot, then the peak of the signal for that affected slot will be reduced. The reduction will be dependent on the magnitude of the short. Therefore, besides learning which slot the short is in, an estimate of the number of shorted turns can be made fairly accurately.

Problems due to saturation effects at full load can occur in analyzing the data and most OEMs now have a dedicated monitor connected to the flux probe to automate the analysis process. This allows the flux probe and monitor to act as stand-alone sensor to alarm when a short turn is detected and notify the operator for investigation.

Probably the most effective method for the detection of shorted turns in solid rotors is the flux probe method. This device maps the flux of the machine as it rotates, indicating possible shorts as changes in the measured waveform. Its main advantage is that it works with the rotor online, capturing the speed-dependent shorts. Its main disadvantages are the expertise required in analyzing the recorded waveforms, and the fact that the machine has to be de-energized and de-gassed for the installation of both core-mounted and wedge-mounted types of probes.

New commercially available units intended for on-line continuous operation, include software that analyzes the waveform and alerts to a possible shorted turn condition.

11.7.13 FIELD-WINDING GROUND DETECTION BY SPLIT VOLTAGE TEST

The "split voltage" test is used locate rotor grounds as a percentage through the field-winding.

For this test to be effective, the resistance to ground of the fault must be less than 5% of the balance of the rotor insulation, and the voltmeter must have high input impedance, when compared to the ground fault. The retaining rings should also be left on in case the ground is to one of the rings.

The test is done by applying up to 150 volts DC, ungrounded, across the slip-rings. A measurement of DC voltage is then taken from the rotor coupling at the turbine end of the forging to one of the collector rings. A measurement is next made from the other collector ring and the same location on the rotor coupling at the turbine end. This way, the two voltage measurements can be compared to estimate how far into the winding the ground has occurred. If the two measurements are equal, the rotor ground fault should be found in the middle of the winding. If there is less than 2% difference between the two readings, then the ground could possibly be at the collector rings.

This test is very useful in helping to determine how much dismantling is required to find the ground. Depending on where the ground is located, it can obviously make a big difference in the time expended to find the fault (Fig. 11.47).

11.7.14 FIELD GROUND DETECTION BY CURRENT THROUGH FORGING TEST

The current through forging test is another test used to locate rotor-winding grounds. In this particular application, the test is used to locate the actual "axial" position of the ground. The retaining-rings should be left on the rotor in case the ground is at one of the rings.

For this test, a DC current of about 500 amps is put through the forging from the tip of the forging at the slip-ring end to the coupling at the other end. A DC ammeter is used to look for the ground position. This is done by attaching one lead of the ammeter to the most outboard slip-ring, and then using the other lead to probe along the axial length of the rotor forging. At the point where the ground is, the current should reduce to zero, or if the current is not zero but only very low, then there will be a polarity change at the ground location (Fig. 11.48).

11.7.15 SHAFT VOLTAGE AND GROUNDING

During operation, voltage may rise on the generator rotor shaft, unless the shaft is grounded. The sources of shaft voltage are well established and identified as voltage from the excitation system due to unbalanced capacitive coupling, electrostatic voltage from the turbine due to charged water droplets impacting the blades, asymmetric voltage from unsymmetrical stator core stacking, and homopolar voltage from shaft magnetization. If these voltages are not drained to ground, they will rise and break down the various oil films at the bearings, hydrogen seals, turning gear, thrust bearing, and so on. The result will be current discharges and electrical pitting of the critical running surfaces of these components. Mechanical failure may then follow.

Inadequate grounding of the rotor will also allow voltage to build on the generator rotor shaft. Inadequate grounding may be due to a problem with the shaft grounding brushes from wear (requiring replacement brushes) or a problem with the associated shaft grounding circuitry if a monitoring circuit is provided.

High shaft voltages can also be caused by severe local core faults of large magnitude, which impress voltages back on the shaft from long shorts across the core. Protection against shaft voltage buildup and current discharges is provided in the form of a shaft-grounding device, generally located on the turbine end of the generator rotor shaft. The most common grounding devices consist of a carbon brush or copper braid, with one end riding on the rotor shaft and the other connected to ground.

Shaft voltage and current monitoring schemes are also provided in many cases to detect the actual shaft voltage level and current flow through the shaft grounding brushes. This has the advantage of providing warning when the shaft grounding system is no longer functioning properly and requires maintenance.

There are numerous monitoring schemes available, and each OEM generally has its own system provided with the TG set when purchased. For older machines with only grounding and no monitoring, a monitoring system can usually be retrofit to the existing ground brushes. The OEM should be consulted when upgrading the shaft monitoring.

11.8 HYDROGEN SEALS

11.8.1 NDE

The main tests done on the hydrogen seals are liquid penetrant inspection (LPI) for cracks and other surface damage, and ultrasonic (UT) for babbit bonding to the seal ring components.

11.8.2 INSULATION RESISTANCE

Megger checks of the seal insulation to ground are done to ensure the rotor shaft is not grounded through the hydrogen seals. This is usually done at only 500 V DC.

11.9 BEARINGS

11.9.1 NDE

The main tests done on the generator rotor bearings are liquid penetrant inspection (LPI) for cracks and other surface damage, and ultrasonic (UT) for Babbitt bonding to the bearing shell.

11.9.2 INSULATION RESISTANCE

Megger checks of the bearing insulation to ground are done to ensure the rotor shaft is not grounded through the bearings. This is usually done at only 500 V DC.

11.10 THERMAL SENSITIVITY TEST AND ANALYSIS

11.10.1 BACKGROUND

The thermal stability analysis is performed when vibrations of unknown origin afflict the generator. The purpose of the analysis is to narrow the search for the origin of the vibrations by ascertaining if the vibrations are from changes in the magnitude of the field current (If) in the field-winding or from other origin.

Generator rotor thermal sensitivity is a phenomenon that occurs in the rotor when its vibration changes as the field current is changed. This has occurred on generators' fields of all manufacturers at one time or another. The thermal sensitivity can be caused by uneven temperature distribution circumferentially around the rotor, or by winding forces that are not distributed uniformly around the rotor's circumference, or by asymmetrical radial gap forces. The primary driver of this second cause is the large difference in coefficients of thermal expansion between the copper coils and the steel alloy rotor forging and components. If the rotor winding is not balanced both electrically and mechanically around the rotor, the generator rotor will be unevenly loaded, which can cause the rotor to bow and cause vibrations to change.

From experience, it is known that rotor thermal sensitivity rarely affects operation when the unit operates in the region between the rated power factor lines, because the rotor is below its rated temperature in this region of operation.

Vibrations due to a thermally sensitive rotor are mostly at running speed frequency.

The vibrations origin can be further discriminated as being “reversible or repetitive” and “irreversible”. Reversible vibrations are those in which the vibration vector, when plotted on a polar graph, will not shift (Fig. 11.49). Irreversible vibrations show a shifting vector (Fig. 11.50). These last ones are the most onerous, as they cannot be balanced over the long run. Almost invariable they result in a winding removal and rewind. To capture the presence of these vibrations, the constant MW test is done in both directions, namely with the field current changed both ways. Figures 11.49 and 11.50 show what to expect in both cases. In the figures the test is started in point A and ends in point G.

Field-related vibrations might indicate the presence of one or more of the following:

- Shorted turns in the field-winding (vibration vector is reversible vs. If for a given number of shorted turns);
- A ratcheting effect (i.e., coils shift to one side of the rotor and the vibration vector becomes irreversible);
- “Sticky coil” (vibration vector tend to be reversible, but vibration changes might be “jumpy”);
- Crease under the retaining-ring (vibration vector may be reversible in the short run but might be of a ratcheting nature in the long run);
- Partial blockage of gas paths inside the rotor (vibration vector is reversible in the short and medium turn, and irreversible if insulation keeps moving- reversible during the test);
- Rotor stiffness dissymmetry (reversible vibrations);
- Wedges that were partially replaced during overhaul, and are not of identical dimensions, resulting in uneven fit along the circumference (vibrations tend to be

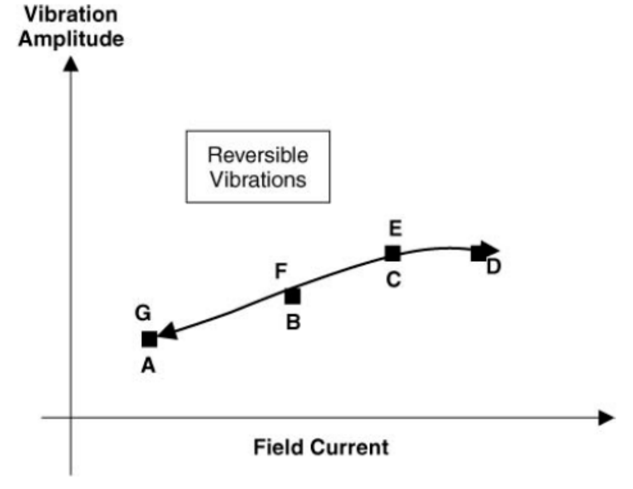


Fig. 11.49 Reversible vibrations in a thermal sensitive rotor. Note that the vibrations have a given value at a given load point. Changing loads will change the vibration, but it will always be the same for a given load. In the rotor of the graph the field current was changed from A to D back to G(= A). As the field current is decreased, the vibrations come back to their original value for each load point.

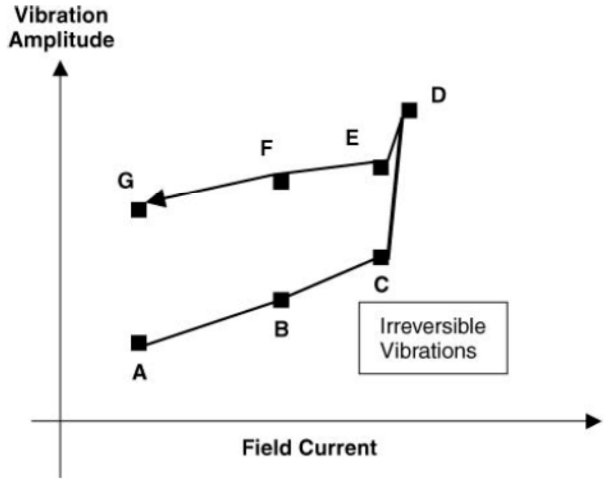


Fig. 11.50 Unlike the situation shown in the previous figure, in the present case the vibrations are not reversible. With every cycle of load they “creep up.” This situation has the potential of requiring a major repair of the rotor in short order.

reversible);
- Insulation that broke and shifted in the slots (reversible or irreversible during test, depending on severity of insulation damage);
- Nonhomogenous forging (vibration vector is reversible - vibration pattern will show up when unit is new or after repair of the forging, e.g., welding and machining).

If the unit does not indicate a field-current dependency, then most probably vibrations are of a mechanical nature.

ROTOR POSSIBLE CAUSES:

- Rotor mechanical unbalance due to a mass shift
  Retaining-ring movement
  Balancing weights shift
  Wedges shift
  Fan shift
  Shift of blocking under the retaining-rings
  Any other mass shift
- Crack in the rotor forging or on one of its components;
- Loose components.

STATOR/FRAME POSSIBLE CAUSES:

- Uneven heating of the stator coils, core, and frame;
- Bearing misalignment;
- H2 seals rub;
- Coupling misalignment;
- Loose footing;
- Loose components;
- Frame twisted.

11.10.2 TYPICAL THERMAL SENSITIVITY TEST

In order to segregate between the various sources, a thermal sensitivity test is performed. The following variables are recorded during the test (others may be added to the list). All manufacturers of large generators perform this type of test with some variances, under one name or another. The following description captures the most common approaches. Consult with the OEM of your unit for the test on your machine.

- MW;
- MVAR;
- Terminal volts;
- Terminal current;
- Field voltage;
- Field current;
- Vibration of all bearings of interest;
- Temperatures of interest;
- Time (hours, minutes) to stamp and correlate all readings.

It is important to verify the unit remains within its capability curve under the entire duration of the test. For that purpose, it is convenient to plan the load points ahead of the test, though it is not critical the actual load points selected during the test closely match those in the plan.

The test has three main parts:

CONSTANT MW AND MVAR

The aim of this test is to capture a rotor that is thermally sensitive due to forging asymmetries (due to the forging process or to machining, welding, etc.), or to stator-frame issues. During this part of the test, the unit's active and reactive power is held constant (AVR manual). The temperature of the generator's hydrogen is changed in steps by controlling flow of cooling water to the hydrogen heat exchangers. Stator water temperature is not changed. It is important to ascertain the unit remains within its temperature operating limits. Readings are taken when the temperatures are stable, and the time is noted (hours, minutes). This test is done at a reduced load point, to "make room" for temperature increases during the test.

CONSTANT MW

During this part of the test, the generator's gross MW output must remain constant. With MW constant, the field current (If) is changed (thus the VARs also change), and readings are taken of the variable parameters. The test is repeated for a number of field-current values. After a new If is set, the machine is let run for a given time to allow temperatures to stabilize, and then the readings are noted and the time is noted. The field current is changed in both directions, to capture "ratcheting" problems.

CONSTANT FIELD CURRENT (IF)

During this part of the test, the If must remain constant - the AVR must be set to manual. Under this condition the MW of the generator is changed in steps. After every change the unit is allowed to stabilize, and readings of the variables of interest are taken and the time is noted.

By analyzing the test results, it is possible to reduce the number of possible causes to one or a very small number. This is very important as it helps minimize the cost of any required outage and repair.